BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

VANCOUVER ISLAND POWER SUPPLY

1982 - 1996

JUNE 1978

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PREFACE

The last major B.C. Hydro report that included a study of future power supply for Vancouver Island was the Task Force report on "Alternatives, 1975 to 1990", prepared in May 1975. This report recommended that the next major addition of power supply to Vancouver Island should be provided through the construction of a double circuit 500 kV ac transmission project from Cheekeye Substation near Squamish to Dunsmuir Substation near Qualicum. This transmission interconnection would allow additional power generated on the mainland to be transmitted to Vancouver Island in the future.

Since this date B.C. Hydro's plans for power supply to Vancouver Island have remained basically unchanged. However, there have been continuing refinements in the design and cost estimates of the proposed 500 kV ac transmission circuits, and also in the cost estimates of alternative transmission and generation projects. Forecasts of future electric load growth on Vancouver Island have also been reduced significantly in recent years.

As planning for the proposed Cheekeye-Dunsmuir transmission project has advanced, this project has aroused a high degree of public interest, and there have been numerous public requests in recent months for an updated planning study that would re-examine the need for this project, and also compare it to alternative generation and transmission projects available. This new report on Vancouver Island Power Supply has been prepared in response to these requests, and it supercedes all previous studies on this subject. Although the load forecast and the costs of alternative sources of power supply have changed greatly in recent years, this report finds that the proposed Cheekeye-Dunsmuir transmission project is still clearly the most economic source of additional power supply for Vancouver Island.

VANCOUVER ISLAND POWER SUPPLY

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SECTION 1.0 - SUMMARY AND RECOMMENDATIONS

1.1 INTRODUCTION

Previous planning studies on Vancouver Island power supply have examined many alternative generation and transmission projects to serve future electric load growth on Vancouver Island. In 1975 the B.C. Hydro Task Force on Future Generation and Transmission Requirements concluded after extensive study, in its report on "Alternatives 1975 to 1990", that the most practical and economic means of serving the Island's future power requirements after 1983 would be the construction of a 500 kV transmission system consisting of overhead lines and submarine cable sections interconnecting Cheekye Substation near Squamish on the mainland with Dunsmuir Substation near Qualicum on Vancouver Island.

This report reviews the technical and economic feasibility of this proposed transmission project, as well as alternative transmission projects and alternative power generation projects on Vancouver Island.

Existing and potential hydroelectric generating capacity on Vancouver Island is insufficient to meet the Island's power needs. The developed hydroelectric plants located on the Island at present provide approximately 30 percent of the Island's electric energy requirements. Most of the power supply to Vancouver Island comes via submarine transmission cables from the mainland. There are also two gas turbine plants on the Island, but these supply very little energy and are used only for emergency power supply.

Load growth on the Island is now forecast to be about 5.6 percent annually, and the existing power supply to the Island will be fully committed by 1982/83. Recent requests for new industrial

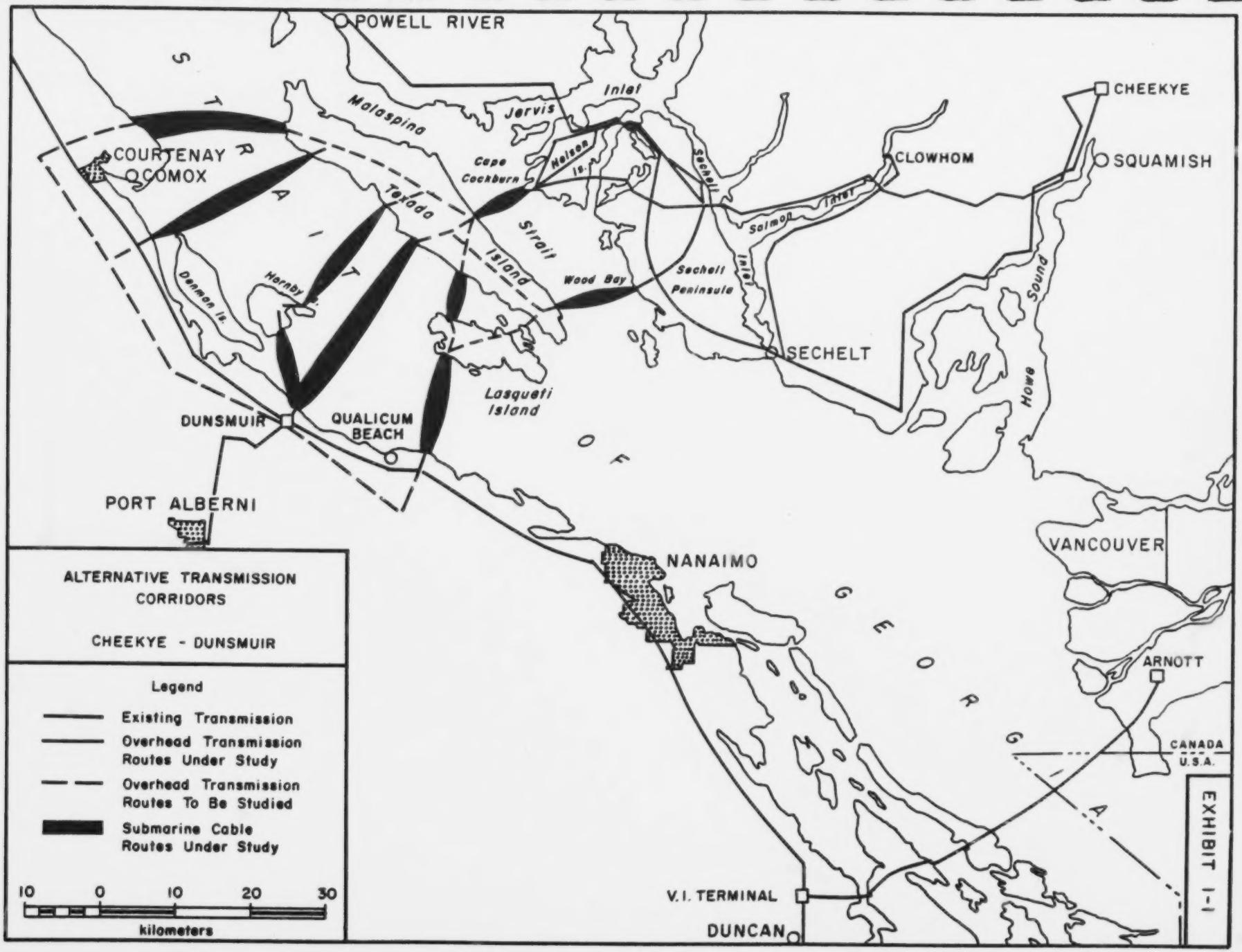
1.1 INTRODUCTION - (Cont'd)

loads on Vancouver Island indicate that total power demands may even exceed available power supply before that date, and that some temporary curtailment of new industrial load growth may be necessary.

1.2 500 kV CHEEKYE-DUNSMUIR TRANSMISSION PROJECT

In order to supply the growing power requirements on Vancouver Island, additional sources must be provided in the next few years. The most suitable alternative from both an economic and technical viewpoint for supplying additional power would be two parallel 500 kV, 3-phase alternating current (ac) transmission circuits from Cheekye Substation near Squamish to Dunsmuir Substation near Qualicum Beach (see Exhibit 1-1). These circuits would be a combination of both overhead conductors and submarine cable sections, with the completion of the first circuit scheduled for October 1983, and the second circuit for October 1986. This additional transmission capacity would allow electric power generated on the mainland to be transmitted to Vancouver Island to serve growing electric loads until 1995. It would also greatly improve the reliability and stability of the Vancouver Island power system.

The right-of-way requirements between Cheekye and Dunsmuir would be for two 500 kV overhead transmission lines with submarine cables crossing Malaspina and Georgia Straits. Each Cheekye to Dunsmuir circuit would have a total length of approximately 160 km, including a 30 to 39 km submarine cable section. This project would also include a new substation on the Sechelt Peninsula which would tie into these circuits to serve the increasing power requirements in this area. This new substation would eliminate the need for an additional 230 kV subtransmission circuit from Cheekye to the Sechelt Peninsula. The total cost of the Cheekye-Dunsmuir transmission project would be about $315 million at 1977 price levels.


POWELL RIVER
CHEEKYE
SQUAMISH
CLOWHOM
COURTENAY
COMOX
Malaspina
Jervis
Inlet
Cape
Cockburn
Nelson
Is.
Sechelt
Inlet
Salmon
Inlet
Toxada
Island
Strait
Hornby
Is.
Denman Is.
Wood Bay
Sechelt
Peninsula
Howe
Sound
SECHELT
Lasqueti
Island
DUNSMUIR
QUALICUM
BEACH
PORT ALBERNI
NANAIMO
VANCOUVER
ARNOTT
CANADA
U.S.A.
V.I. TERMINAL
DUNCAN
STRAIT OF GEORGIA
ALTERNATIVE TRANSMISSION
CORRIDORS
CHEEKYE - DUNSMUIR
Legend
Existing Transmission
Overhead Transmission
Routes Under Study
Overhead Transmission
Routes To Be Studied
Submarine Cable
Routes Under Study
10 0 10 20 30
kilometers
EXHIBIT I-1

1.3 ALTERNATIVE TRANSMISSION PLANS

Four alternative transmission systems for supplying power to Vancouver Island after 1983 have been examined: a 500 kV ac overhead transmission system from Kelly Lake Substation to Dunsmuir Substation via Knight and Bute Inlets; an additional direct current (dc) submarine cable transmission system between Arnott Substation and Vancouver Island Terminal; and two submarine cable alternatives between Cheekye Substation and Dunsmuir Substation: a 230 kV ac system and a ±450 kV dc system.

A 500 kV overhead transmission system via the Bute and Knight Inlets would be the most expensive alternating current alternative and also the least secure. The circuits would be practically inaccessible during the winter months when outages would be most likely to occur.

A new high voltage direct current transmission system between Arnott Substation near Tsawwassen and Vancouver Island Terminal near Duncan would require five additional cables on the sea bottom where 12 already exist. Even if it were physically possible to install the additional cables in this narrow corridor, this alternative would concentrate almost all the power supply for Vancouver Island along one corridor between Arnott and Vancouver Island Terminal. Increasing ship and ferry traffic and waterfront construction activity in this area would increase the hazards to the major source of power to the Island. This alternative is also considered unacceptable because part of the cable circuits would lie in United States waters and would require at least 3 years to obtain the necessary approvals, and because it would impose additional loading on transmission into the Lower Mainland. Furthermore, since transmission circuits on Vancouver Island north of Duncan are already heavily loaded, the logical place to deliver additional power is in the Dunsmuir area, not the Duncan area.

1.3 ALTERNATIVE TRANSMISSION PLANS - (Cont'd)

Other transmission alternatives have also been examined, including an HVdc transmission system from Cheekye to Dunsmuir, and overhead transmission routes from Kelly Lake Substation near Clinton via Knight and Bute Inlets to Dunsmuir, but these transmission alternatives would be much more expensive to build and difficult to maintain.

Both the 230 kV ac and the 450 kV dc alternatives for transmitting power via submarine cables from the mainland near Sechelt to Dunsmuir Substation are technically feasible and would provide secure power to Vancouver Island. The ac alternative, however, is more economic and technically preferable. The dc alternative, in addition to its higher cost and somewhat lower reliability, would present difficult problems in both voltage and frequency control.

The 230 kV ac transmission alternative would provide secure power to Vancouver Island to meet the forecast load only until 1991 and a new project would then be required in 1991. The proposed 500 kV ac system will provide firm power to Vancouver Island until about 1995, thereby deferring the need for a new project another 4 years. The capital cost of a 230 kV transmission system would be less, but when the cost of additional projects required to meet load growth from 1991 to 1995 is added, there would be no saving in total system cost with this plan.

1.4 VANCOUVER ISLAND GENERATION ALTERNATIVES

Another alternative source of power supply would be to build more generating facilities on Vancouver Island. The remaining undeveloped hydro potential on the Island is limited to a few small projects. The largest undeveloped hydro sites at Kokish, Duncan Bay and Ladore Unit 3 would have only limited generating capacity, they would contribute little energy to the power system, and they could have significant

environmental impacts. A pumped storage hydro project might be developed, but it would not contribute any net energy.

The feasibility and public acceptability of a nuclear project on Vancouver Island have not yet been determined. In any case, a nuclear project on the Island could not be built before 1991 due to the long lead time required for project licencing and construction; therefore nuclear power would not be a feasible alternative to serve load growth before that date. It would, however, probably be the most economical power source to serve load growth after 1991 if it is feasible.

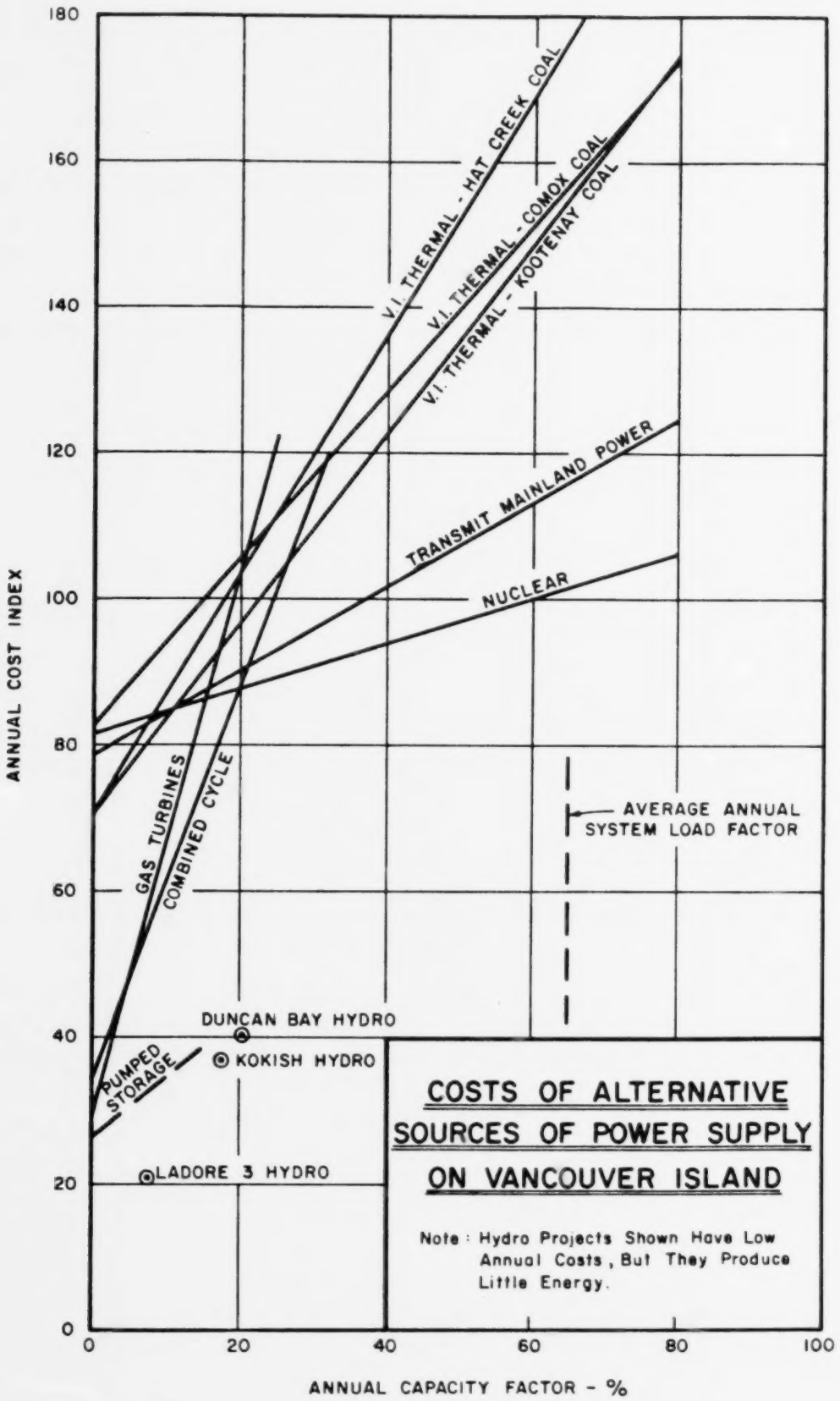
Additional oil-fired gas turbine capacity could be built on the Island, but it would be extremely expensive to operate for base load service due to its high fuel-oil cost.

The only remaining feasible and economic alternative to the proposed 500 kV interconnection would be to build a coal-fired thermal powerplant on Vancouver Island. Such a thermal plant could use either Comox coal mined on the Island, or Hat Creek coal or East Kootenay coal transported to a powerplant site on the Island. The fuel costs would be higher than fuel costs for a mainland plant however. A coal-fired thermal plant could not be completed before October 1986, and this alternative would require the construction of another gas turbine plant for service in October 1983, and probably the Duncan Bay hydro project in 1984 to meet interim load growth. A 600 MW coal-fired thermal plant would be able to serve load growth from 1986 until 1990, and then a nuclear plant might be built on the Island in 1991 to serve load growth after that date.

1.5 ECONOMIC COMPARISON OF ALTERNATIVES

The annual costs of these alternative sources of power supply on Vancouver Island are shown in Exhibit 1-2. Annual costs are shown as a function of project capacity factor, which is the ratio of average power produced by a project over a year to its maximum generating capacity. The average annual load factor of power demand on Vancouver Island, for reference, is about 65 percent. Exhibit 1-2 shows that the most economical long-term power source would be nuclear power, but this alternative would not be available until 1991 at the earliest. The cost of transmitting mainland power to the Island will be much lower than any other alternative base load (i.e. high capacity factor) power source from 1983 until 1991. Some economic peaking capacity could be developed on the Island at the Kokish, Duncan Bay and Ladore hydro projects and with pumped-storage hydro, but the small size and low capacity factors of these plants would not allow them to provide the required increase in base load power supply for the Island.

The total cost of an alternative power supply plan that relies on Vancouver Island generation without additional transmission from the mainland has been studied carefully. Such a plan would allow a reduction in total capital costs due to elimination of the 500 kV Cheekye-Dunsmuir transmission project, but it would have much higher annual operating costs. It would also require an additional 230 kV transmission line in 1983 from Cheekye to Sechelt to serve future load growth in the Sechelt-Powell River area. An alternative generation expansion plan with a 600 MW coal-fired thermal power development from 1986 to 1989 and a nuclear power development starting in 1991 would be significantly more expensive than the proposed transmission plan, and would have an additional total discounted cost of about $430 million in 1977 at a 10 percent discount rate. Most of this cost increase is due to the high cost of coal for powerplant fuel on the Island.


ANNUAL COST INDEX
180
160
140
120
100
80
60
40
20
0
0
20
40
60
80
100
ANNUAL CAPACITY FACTOR - %
V.I. THERMAL - HAT CREEK COAL
V.I. THERMAL - COMOX COAL
V.I. THERMAL - KOOTENAY COAL
TRANSMIT MAINLAND POWER
NUCLEAR
GAS TURBINES
COMBINED CYCLE
AVERAGE ANNUAL SYSTEM LOAD FACTOR
DUNCAN BAY HYDRO
KOKISH HYDRO
PUMPED STORAGE
LADORE 3 HYDRO
COSTS OF ALTERNATIVE SOURCES OF POWER SUPPLY ON VANCOUVER ISLAND
Note : Hydro Projects Shown Have Low Annual Costs, But They Produce Little Energy.

1.5 ECONOMIC COMPARISON OF ALTERNATIVES - (Cont'd)

If an early nuclear power program is not feasible or publicly acceptable, additional coal-fired thermal power would have to be substituted for future nuclear power, and the total cost of the Vancouver Island alternative generation plan would increase substantially. An alternative generation expansion plan with a 1200 MW coal-fired thermal power development from 1986 to 1995 and a nuclear power development starting in 1996 would have an additional total discounted cost of about $950 million.

1.6 LOAD REDUCTION ALTERNATIVES

Another alternative to increasing total power supply with additional transmission or generation projects might be to reduce total power demand through load reduction measures. The possible measures considered in this report include increased electricity conservation, increased industrial self-generation, and the supply of natural gas to Vancouver Island.

B.C. Hydro already has an active energy conservation program, and increased attention will be directed in the future toward promoting additional electricity conservation on Vancouver Island. Conservation measures are entirely voluntary however, and although they will help to reduce load growth somewhat, their overall impact is still limited. In the absence of stricter provincial and federal measures, it is unlikely that voluntary electricity conservation will do more than marginally delay the need for additional power supplies on Vancouver Island.

The possibility of reducing industrial loads through promoting increased co-generation of power by the forestry industry with hog fuel and wood waste as boiler fuels has also been considered. The supplies of hog fuel on Vancouver Island are limited however, and are not expected to support any significant increase in industrial co-generation.

1.6 LOAD REDUCTION ALTERNATIVES - (Cont'd)

The feasibility of supplying natural gas to Vancouver Island is also being studied. Natural gas would be able to serve most future space heating and water heating loads, and it would reduce the future long-term growth rate of power demands by about 1 percent per year after 1982. Such a gas supply would not result in any significant reduction of electric power loads in its initial years of operation, however. It would definitely not eliminate the need for additional power supply to Vancouver Island, and it would not even delay the required in-service date of the first circuit of the Cheekye-Dunsmuir transmission project.

1.7 CONCLUSIONS

This study shows that the Cheekye-Dunsmuir 500 kV transmission interconnection will be the most economic feasible source of future power supply to Vancouver Island after 1982. It is therefore recommended that power supply to Vancouver Island be increased by constructing a 500 kV ac transmission system between Cheekye Substation on the mainland and Dunsmuir Substation on the Island, with 500 kV ac submarine cable circuits across the Malaspina and Georgia Straits. This transmission project is more reliable than other transmission or generation alternatives, and it is the only project far enough advanced in its planning to ensure that all load growth on Vancouver Island can be served with confidence after 1983.

Although 500 kV underground cables have been installed elsewhere and are operating successfully, this will be the first installation of 500 kV submarine cable in the world. B.C. Hydro is confident that the required high quality of manufacture and installation of the cable can be provided to meet the rigorous requirements for providing security of power transmission and protection of the environment.

1.8 ENVIRONMENTAL IMPACT AND ROUTE SELECTION STUDIES

The Cheekye-Dunsmuir transmission project will have some adverse environmental impacts along its route. B.C. Hydro is well aware of these impacts, and will attempt to select transmission routes and design the project in such a manner that adverse impacts and social costs will be minimized wherever it is possible to do so at reasonable cost and without compromising the security of power supply. An examination of alternative sources of power supply however suggests that the total environmental impact of these alternatives in most cases would be even greater than that of the proposed transmission project.

The technical problems related to this transmission project will impose important constraints on the route selection and transmission cable design. The physical terrain between Cheekye Substation and the Sunshine Coast is rough mountainous country in which snowslides and avalanches are common and long span water crossings will be required. Because of these problems, all possible corridors are being critically evaluated to ensure the selection of a technically feasible and secure route.

The submarine portions of the circuits present special technical problems of their own. It will be desirable to locate these cables on smooth seabeds, and to limit the maximum span of underwater crossing. Long cable crossings would probably require splices, which could reduce the reliability of the cable and its power supply.

Beak Consultants Limited of Vancouver have been retained to provide environmental and route investigation studies for the Cheekye to Dunsmuir 500 kV circuits. Broad transmission corridors are under study in Phase I of this study program, and detailed transmission routes within the recommended corridor will be determined in Phase II, as outlined in the Environment and Land Use Committee Guidelines for

1.8 ENVIRONMENTAL IMPACT AND ROUTE SELECTION STUDIES - (Cont'd)

Linear Development. Volume I of the Phase I study, dealing with overhead transmission corridors from Cheekye to Cape Cockburn on Nelson Island at the north end of the Sechelt Peninsula, was completed recently and has been made available for public review. The recommended mainland corridors from this study are shown in Exhibit 1-1. Volume II of this Phase I study, dealing with transmission corridors across the Strait of Georgia to Dunsmuir Substation, is currently underway and should be completed by the fall of 1978. Several alternative submarine cable routes are shown in Exhibit 1-1, but other alternative routes will also be examined in Volume II of this study.

The Phase I Route Selection Reports will provide a source of organized information for those concerned with the location of the transmission lines, such as the relevant regional districts, government resource agencies, property owners and the general public. In this respect they will serve as the basic information and discussion documents for planning meetings as required with those affected by or interested in this project. Following discussions with the public and other external agencies, a basic transmission corridor will be chosen and more detailed studies (Phase II) of "site specific" impacts and exact transmission routes will begin.

SECTION 2.0 - INTRODUCTION

2.1 EXISTING POWER SUPPLY ON VANCOUVER ISLAND

During the past 20 years, the annual electric energy consumption on Vancouver Island has increased six-fold. To keep pace with this rapid increase in demand, the number of major generating stations on Vancouver Island has increased from three in 1955 to eight in 1974. During this period a high voltage transmission interconnection with the mainland was also constructed and this now delivers about 70 percent of the Island's electric energy requirements. The existing power plants on Vancouver Island and a history of their development are described briefly in this Section.

In the late 1800s and early 1900s, electric energy was supplied to the major urban centres on Vancouver Island by a number of small hydroelectric and steam-electric generators. As the demand for electric energy grew, these small plants were not sufficient to meet the increasing electric load. In 1910 the first major hydro development on Vancouver Island was undertaken on the Jordan River about 43 miles west of Victoria, and by 1911 the first generating unit was in service at a rated capacity of 3.2 megawatts (MW). Additional units were later added to the Jordan River powerhouse and by 1931 the plant contained four units with a total generating capacity of 26 MW. The original Jordan River plant remained in operation until 1969 when an extensive redevelopment of the project was started. The new Jordan River plant was completed in 1971 and now consists of a single 160 MW unit.

Another early hydroelectric project was constructed in 1913 on the Puntledge River near Courtenay. This 7 MW generating station was owned by Canadian Collieries Ltd. and it provided power for their nearby coal mining operation. In 1953 the Puntledge plant was purchased

by the B.C. Power Commission and the original project was redeveloped. The installed capacity was increased to 27 MW and the new plant began service in 1955.

In 1945 development of the hydroelectric potential of the Campbell River was started. This development is the largest on Vancouver Island and was carried out in three stages. The first stage, the John Hart Project, was completed in 1953 and has an installed capacity of 120 MW. The second and third stages, the Ladore Falls and Strathcona Projects, were started in 1955. The two-unit Ladore Falls plant was completed in 1957 and has an installed capacity of 54 MW. The first 33.75 MW unit of the Strathcona project entered service in 1958 and a second similar unit was added in 1968.

The last major hydro development on Vancouver Island was started in 1955 on the Ash River about 18 miles north of Port Alberni. This project was completed in 1959, and the powerplant consists of a single 25.2 MW generating unit.

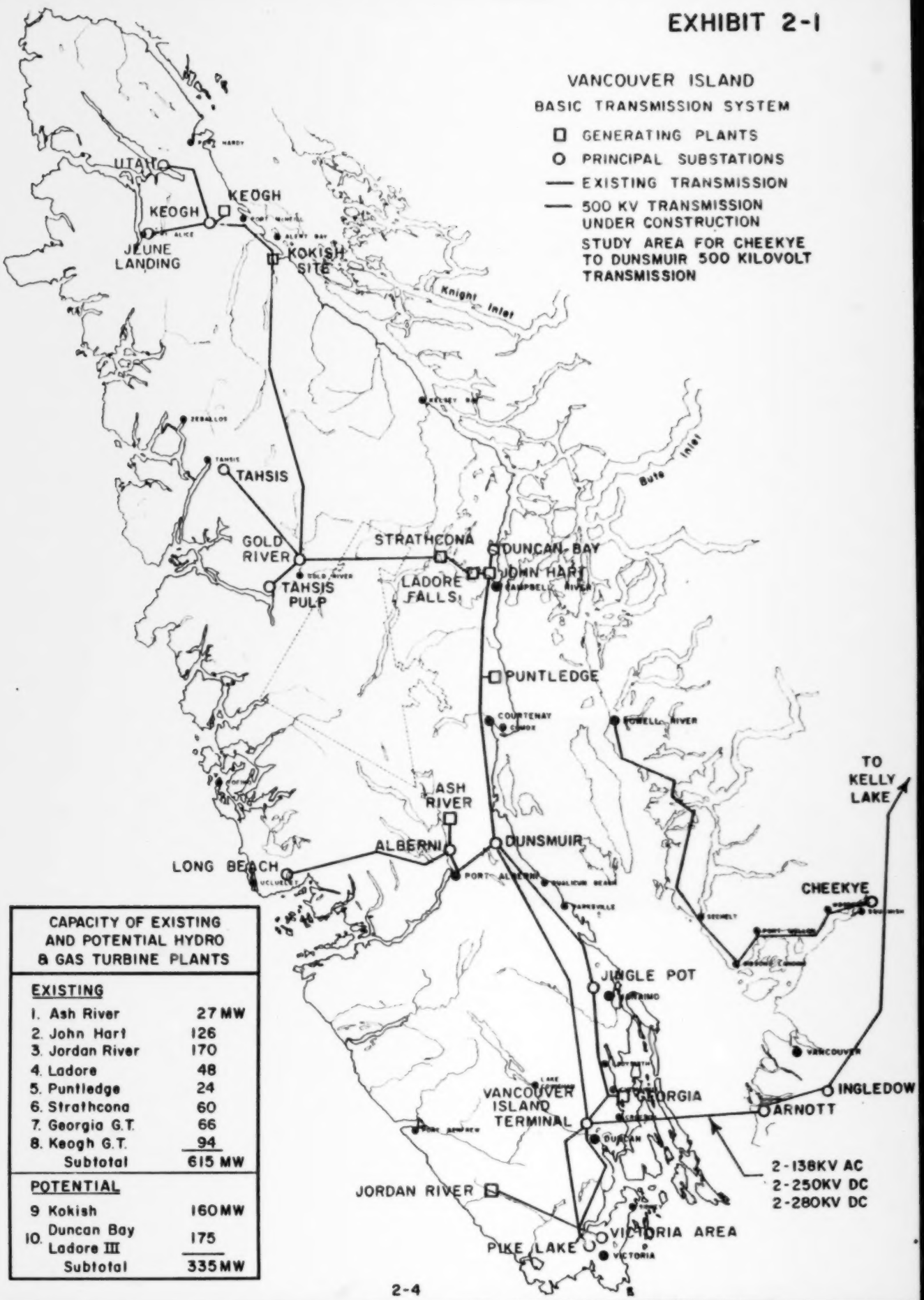
By the mid-1950s it was evident that Vancouver Island's hydro resources would be inadequate to meet the future demand for electric energy on the Island, and in 1956 a high voltage transmission link with the mainland was installed to supply the Island's growing electric requirements. This transmission link connected Arnott Substation near Ladner with Vancouver Island Terminal just north of Duncan, and it consisted of two 138 kV ac submarine cable circuits with a total capacity of 256 MW. In 1969 a 260 kV dc submarine cable circuit was also installed with a rated capacity of 312 MW. In 1977 another 280 kV dc submarine circuit was installed. Valve 1 of this circuit is now in operation at 140 kV dc. This voltage will be increased to 280 kV in February 1979, when the total transmission capacity of this circuit will be 476 MW. A total of 12 submarine cables are laid down for the complete transmission link between the mainland and Vancouver

Island, including seven 138 kV ac cables and five dc cables. This transmission presently supplies about 70 percent of the Island's electric energy requirements, and will have a total rated capacity of 1044 MW and a peak capacity of 1076 MW by 1979.

There are also two gas turbine generating plants on Vancouver Island to supply power during periods of peak demand or during emergency situations. The Georgia gas turbine plant near Chemainus was constructed during 1956-59 and has an installed nominal capacity of 75.5 MW. The Keogh gas turbine plant near Port Hardy has 94.5 MW of generating capacity. Keogh Unit 1 of 40.5 MW was completed in 1974. Keogh Unit 2 of 54 MW was installed in 1977, but is experiencing commissioning problems and will not become operational until October 1978. These oil fired gas turbine plants are rarely operated due to their high fuel costs. There are also small diesel-electric generators to supply the towns of Tofino, Bamfield and Alert Bay.

The locations of the projects described above are shown in Exhibit 2-1. The power supply from each of these projects is summarized in Table 2-1. The effective capacities shown in Table 2-1 may differ slightly from the rated nameplate capacities of these projects as described above. The transmission capacities shown in this table are the winter ratings at the sending end of the line (at Arnott Substation). The 260 kV dc Pole I circuit has a rated capacity of 312 MW and a 2-hour overload capacity of 344 MW. The 280 kV dc Pole II circuit has a winter rating of 476 MW and a summer rating of 370 MW. Firm hydro energy is based on hydro generation during the peak load months of December to February during the worst historic drought of 1971 to 1972. This seasonal generation is adjusted to an annual basis to determine nominal firm annual hydro energy, and is in some cases higher than average annual energy. The firm gas turbine energy is based on a maximum annual capacity factor of 20 percent, and firm transmission energy is based on a maximum annual capacity factor of 84 percent and the cables' rated winter capacity.

EXHIBIT 2-1



CAPACITY OF EXISTING AND POTENTIAL HYDRO & GAS TURBINE PLANTS	
EXISTING	
1. Ash River	27 MW
2. John Hart	126
3. Jordan River	170
4. Ladore	48
5. Puntledge	24
6. Strathcona	60
7. Georgia G.T.	66
8. Keogh G.T.	94
Subtotal	615 MW
POTENTIAL	
9 Kokish	160MW
10. Duncan Bay Ladore III	175
Subtotal	335MW

TABLE 2-1

EXISTING VANCOUVER ISLAND POWER SUPPLY

Plant	Nameplate Capacity MW	Effective Capacity MW	Firm Energy GWh/yr	Average Energy GWh/yr
Hydro				
Ash River	25.2	27	152	206
John Hart	120	126	869	857
Jordan River	150	170	141	249
Ladore	54	48	297	240
Puntledge	27	24	120	156
Strathcona	67.5	60	250	232
Subtotal	443.7	455	1829	1940
Gas Turbines				
Georgia	75.5	66	115	
Keogh	94.5	94	165	
Subtotal	170	160	280	
Mainland Interconnection				
AC (1L17) 138 kV		128	940	
AC (1L18) 138 kV		128	940	
DC Pole I: 260 kV				
Valve 1		172	1150	
Valve 2		172	1150	
DC Pole II: 280 kV				
Valve 1 Feb. 1977		238	1750	
Valve 2 Feb. 1979		238	1750	
Subtotal		1076	7680	
Total Installed Supply		1691	9790	
Required Reserve		231	270	
Total Dependable Supply		1460	9520	

2.1 EXISTING POWER SUPPLY ON VANCOUVER ISLAND - (Cont'd)

Table 2-1 also shows the reserve power requirements and total dependable power supply. The reserve power requirements, which are discussed further in Section 6.2, provide an allowance for possible forced outages of sources of power supply and other contingency factors.

It will be necessary to schedule the retirements of two existing projects within the planning time horizon of this study. The 138 kV ac submarine cables have an expected useful lifetime of about 35 to 40 years, and are tentatively scheduled for retirement in 1996. The Georgia gas turbine plant is also expected to have a useful lifetime of about 35 years, and is tentatively scheduled for retirement in 1993, subject to later review.

The basic transmission system on Vancouver Island shown in Exhibit 2-1, is presently made up of three 138 kV circuits which extend from Victoria in the south to Campbell River in the north, except for a section between Nanaimo and Qualicum Bay which has only two 138 kV circuits. Most of this system has been in service for over 25 years. Vancouver Island Terminal north of Duncan is a focal point of this system. It is the receiving station for power transmitted via cables from the mainland and feeds electricity both north and south into the transmission system.

2.2 SCHEDULED ADDITIONS TO 1982

The second HVDC submarine cable to the Island has recently been installed and is now operating at 140 kV dc. This will be increased to 280 kV in February 1979, when the total transmission capacity of this cable will be 476 MW. This increase in power supply will be able to supply load growth on the Island until 1982/83.

2.2 SCHEDULE ADDITIONS TO 1982 - (Cont'd)

The existing 138 kV transmission system on the Island will be supplemented in 1979 by a planned new high voltage transmission system consisting of two parallel single circuit 500 kV lines. These lines will run between a new substation planned near Pike Lake in the Victoria area and Dunsmuir Substation in the Qualicum area, with 230 kV links to Vancouver Island Terminal near Duncan. The new transmission lines will be designed and constructed for 500 kV, but will be operated at 230 kV until the 1990s. The first of the two lines is scheduled for completion in 1979. System reliability objectives will require the second line to be constructed in the mid-1980s.

2.3 EXISTING POWER DEMANDS

In the fiscal year April 1977 to March 1978, B.C. Hydro's total electric energy sales on Vancouver Island were 5916 million kilowatt-hours (kWh). This figure represents almost six times the sales in 1956. To supply this electric demand, B.C. Hydro had to generate 6392 million kWh of electric energy, which includes the amount sold and the amount lost in transmission and distribution.

The existing electric load on Vancouver Island can be broken down into the following categories:

1. Residential load - in 1977/78 there were 176,183 residential accounts on Vancouver Island and total residential energy sales were 1736 million kWh, which is about 29.3 percent of the total sales.

2. Bulk industrial load - in 1977/78 there were nine bulk industrial customers on Vancouver Island who accounted for 2917 million kWh of energy sales, or 49.3 percent of the total sales. The major consumer in this area was the pulp and paper industry, which

2.3 EXISTING POWER DEMANDS - (Cont'd)

represented about 40 percent of the total electric load on Vancouver Island. Another large consumer was the Utah Mining Company copper mine near Port Hardy, which accounted for about 7 percent of total sales. Other industrial loads include cement manufacturing and industrial chemicals.

3. General load - this section of the load includes commercial accounts such as shopping centres, office buildings, service stations, small industrial loads, street lighting, hospitals, schools, etc. In 1977/78 there were about 24,250 general accounts and the total for general energy sales was 1263 million kWh, or about 21.3 percent of all Vancouver Island sales.

B.C. Hydro's generating system must be capable not only of supplying the annual energy load on the system, but also of meeting the peak seasonal load. In 1977/78 the peak hour electric load on Vancouver Island was 1,120,000 kW and the annual energy requirement was 6392 million kWh (including losses).

2.4 LOAD FORECAST

(a) Planning Philosophy

Electric power loads on Vancouver Island have grown two-fold in the last 10 years and almost six-fold in the last 20. This rapid growth is largely because Vancouver Island has a relatively young, resource-based economy which has not yet matured. Nevertheless, the total demand for electricity has increased continuously with the growth of the economy, and total power demands on B.C. Hydro, as well as most other electric utilities in North America, have almost doubled every 10 years at historic rates of growth over the past decades. This has led in recent years to a power crisis of unprecedented proportions for

many electric utilities in North America. This crisis is due both to the rapid growth of power demands, and also to the increasing public opposition to the environmental impact caused by new power projects. Many people are beginning to question the wisdom of such unconstrained growth, and its accompanying consumption of limited natural resources and effect on the environment. It is obvious that unconstrained exponential growth cannot continue forever at historic rates; but the question of more immediate concern is will growth continue in the near future, and at what rate?

The question of whether or not growth should continue and whether or not this is to society's best long-term benefit involves many fundamental value judgements that are clearly beyond B.C. Hydro's mandate. Any policy to limit growth must be debated and decided on the highest political levels, with full public participation in such a debate. B.C. Hydro, as a public corporation, cannot establish such policies unilaterally, but has only the authority and responsibility to serve the public by supplying reasonably foreseeable future power demands at the minimum cost subject to the constraints of reliability, safety and environmental and public acceptability of new sources of power supply. B.C. Hydro can and does promote electricity conservation, but such conservation is entirely voluntary in nature. In view of these responsibilities, B.C. Hydro cannot base its planning for future power supply on wishful thinking about what economic development should be, or what would be to its greatest advantage, but rather planning must be based on realistic, informed and experienced judgements about what development probably will be. That judgment today is that growth of future power demands will continue, although at a rate that is significantly lower than historic growth rates.

2.4 LOAD FORECAST - (Cont'd)

This reduction in forecast future growth rates reflects both the recent slowdown in economic growth, and a broad consensus of economic opinion that now expects a sustained period of considerably slower growth for British Columbia in the next decade than experienced over the past 25 years. Adding to this are rapidly rising energy costs and increasing conservation efforts - all factors which must lend a general air of caution to longer term projections. In spite of such conservation efforts however, British Columbia's favourable climate and living conditions are expected to continue to attract population to this province, although the rate of future population growth should be lower than in recent decades.

(b) Load Forecast Procedure

B.C. Hydro prepares estimates of electric energy sales, losses, gross energy requirements and peak demands annually for a 10-year budget period and 10 and 20-year planning periods. Energy forecasts are made first and peak demand estimates are then established by the application of load factors to energy.

B.C. Hydro presently provides electricity to about 200,000 customers in several districts on Vancouver Island. Nine of these customers are large industrial bulk loads served at transmission voltage and account for 49 percent of total electric energy sales. Forecast procedures start by isolating these large customers, with each to be analyzed on an individually named basis. Remaining sales are forecast in detail for each district by load categories, i.e. residential, general under 35 kW, general 35 kW and over, street lighting and company use. Categories are then added to obtain a total sales forecast for each district. The districts are summated for the Vancouver Island Division, bulk sales are added and total sales are obtained for the 10-year

forecast. These data at the divisional level are principally used for determining administrative operating costs and sales revenues. For plant operation and planning purposes, applicable district sales forecasts are again summated, bulk sales and losses are added and gross energy and peak demand requirements are ascertained for power districts and generating systems. The peak demand estimates are based on normal weather and these normal winter peak demands may be exceeded by as much as 6 percent should colder weather occur in say 1 year out of 10. For the additional 10-year planning period, a general extension of total load projections is made consistent with population estimates and related economic indicators.

Category sales estimates other than bulk, are based on detailed forecasts of numbers of customers, energy use per customer, commercial and industrial activity. These data are provided by power district managers and B.C. Hydro head office with heavy reliance on district information for the short-term, wherein each district manager provides: a 2-year projection of kWh sales by customer class, a 5-year projection of customers, and a written summary of short-term commercial and industrial activity. Bulk sales forecasts are prepared in consultation with each of the customers involved to incorporate their latest outlooks. Bulk allowances for unspecified growth are made at head office by assessing the probabilities of various proposed new industrial developments.

Concurrent with the foregoing forecast preparation, B.C. Hydro's Distribution Engineering Department prepares independent forecasts of substation peak demands for each power district. The Economic Analysis Department and Distribution Engineering together meet with divisional staffs to review the peak load

projections and, considering load diversity, arrive at a consensus for distribution planning purposes.

Only the 10-year probable forecast is prepared by the Power District detail described above. The further extension of the probable forecast from 10 to 20 years, and also low and high forecasts for the 10 and 20-year periods are prepared by sales categories at the total B.C. Hydro level only. For these projections, residential customers and sales are related to total population served, general sales are related to gross provincial product estimates and bulk sales incorporate growth allowances based on varying degrees of probability as mentioned previously.

Load forecasting involves a complex application of judgments in such wide ranging factors as future population growth, development and diversification of the economy, expansion of land usage and advances in technology. Projections become progressively more conjectural with extension into the future. They are not targets, but rather a considered expectation of what may reasonably occur under given sets of conditions. They provide a rational basis for specific short range planning and general planning for the longer term. Caution must be exercised that results do not get lost in a myriad of assumptions and formulae that lend an apparent accuracy or credibility to forecasts which they simply do not have.

(c) Vancouver Island Load Forecast 1978-1998

Electric power loads on Vancouver Island have grown rapidly in the past, and the peak load on the Island now is 1120 MW. It is expected, however, that future growth will be at a significantly lower rate than historic rates. The forecast load growth for the next 10 years is about 5.6 percent annually. This compares to an historic rate of 8.8 percent average annual growth

2.4 LOAD FORECAST - (Cont'd)

of electric energy demands since 1964. The forecast of future gross peak and energy requirements on Vancouver Island, including all transmission and distribution losses, is summarized in Table 2-2.

Much of the reduction in load growth on Vancouver Island can be attributed to the slowdown of the industrial sector. The historical rate of industrial load growth from 1964 to date has been about 7.6 percent annually, and industrial loads now constitute half of the electric energy demand on Vancouver Island. There are only limited firm plans for industrial expansion on Vancouver Island in the near future however, and bulk industrial load growth over the next 10 years was forecast in 1977 to be only 2.0 percent annually, about one quarter of the historic growth rate.

There are recent indications, however, that this industrial forecast is too low, and that industrial expansion could be higher in the near future if power supply is available. Recent requests and enquiries for new industrial loads on Vancouver Island before 1983 have totalled about 170 MW over and above the forecast industrial load growth, and there is serious doubt whether it will be possible to serve any of these new load requests until October 1983, when the proposed Cheekye-Dunsmuir transmission project is completed. These new industrial load requests are not included in the load forecast shown in Table 2-2, which was prepared in September 1977, and they are not considered explicitly in the alternative power supply plans developed in the report.

In the residential sector, much of the load growth is due to the increasing use of electric space heating on Vancouver Island. In 1976/77, only 14 percent of total residential accounts

TABLE 2-2

VANCOUVER ISLAND ELECTRIC LOAD FORECAST

Year April-March	Energy Requirements* GWh	Peak Load* MW
1977/78**	6,390	1,120
1978/79	6,955	1,155
1979/80	7,410	1,230
1980/81	7,775	1,295
1981/82	8,120	1,365
1982/83	8,610	1,450
1983/84	9,050	1,535
1984/85	9,520	1,625
1985/86	10,000	1,720
1986/87	10,525	1,820
1987/88	11,050	1,925
1988/89	11,600	2,030
1989/90	12,180	2,140
1990/91	12,790	2,260
1991/92	13,430	2,390
1992/93	14,100	2,520
1993/94	14,780	2,650
1994/95	15,490	2,790
1995/96	16,230	2,930
1996/97	17,010	3,090
1997/98	17,820	3,250

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* Includes transmission and distribution losses and losses on the ac and dc underwater cables from the mainland to Vancouver Island.

** Actual load for 1977/78.

used electric space heating. However, with the rapid increase of fuel oil prices in recent years, and the prospects of oil supply scarcity in the future, electric heating has become much more popular. The proportion of new dwelling units which install electric space heating has been increasing rapidly. This is expected to increase to 80 percent of new dwelling units added over the next 10 years, unless natural gas is supplied to Vancouver Island.

The growth in the total number of residential accounts is forecast to be about 4.2 percent annually. This is higher than the population growth forecast, due to a lower average number of occupants per residential unit in the future. The growth in average electric energy use per residential account is estimated to be only 1.7 percent annually for non-electric heating accounts and 0.8 percent annually for electric heating accounts. However, electric heating accounts use twice as much electricity as non-electric heating accounts, and the rapid growth of electric heating will consequently result in an estimated 7.6 percent average annual growth of total residential power demands. This compares with a historic growth rate of 9.1 percent annually for the residential sector.

The forecast growth rate of power demands in the general and commercial category is expected to be about 7.4 percent annually, compared to a historic growth rate of 9.2 percent annually for this sector.

The resulting forecast growth rate of 5.6 percent average annual growth of total electric energy demand on Vancouver Island is only 64 percent of the actual historic growth rate of 8.8 percent for such demands. This forecast is also less than the

forecast annual growth rate of 6.6 percent for average electric energy demands on the mainland.

The load forecast for Vancouver Island would be reduced if a natural gas supply becomes available in the future. The B.C. Hydro Gas Group and the B.C. Energy Commission are currently studying the economic feasibility of building a gas pipeline from the mainland to Vancouver Island. A future gas supply would be able to serve much of the growth in new residential and commercial heating requirements, which would otherwise be served by electric power and fuel oil. However, a gas pipeline could not be completed until 1982, and electric load growth until this date would be unaffected by a new pipeline. A new source of electric power would still be required then in 1983 even with a gas supply. After 1982/83, if an economically priced gas supply were available, the future annual growth rate in total electric energy demand on Vancouver Island could be reduced by about 1 percent. The effect of such a natural gas supply on planning for future power supply to Vancouver Island is studied further in Section 7.3.

SECTION 3.0 - 500 kV TRANSMISSION POWER SUPPLY (CHEEKYE-DUNSMUIR)

3.1 DESCRIPTION OF THE PROJECT

The proposed plan for additional power supply to Vancouver Island is a new 500 kV ac submarine transmission interconnection from the mainland to Vancouver Island which will allow the transmission of additional mainland power to supply electric load growth on Vancouver Island after 1983. This interconnection would comprise two 500 kV ac single circuit transmission lines with a capacity of 1100 MW each from Cheekye Substation on the mainland near Squamish to Dunsmuir Substation on Vancouver Island near Qualicum Beach. The first circuit is planned for completion in 1983 and the second circuit in 1986. The total cost of this project, which is summarized in Table 3-1, would be about $315 million at 1977 price levels.

The right-of-way requirements between Cheekye and Dunsmuir would be for two 500 kV overhead transmission lines with underwater cables crossing Malaspina and Georgia Straits as required. The overhead transmission would be the same design and have the same right-of-way requirements as the Peace River 500 kV system. The transmission line right-of-way would be about 400 ft (125 m) wide. Each Cheekye to Dunsmuir circuit would have a total length of approximately 160 km, including the 30 to 39 km submarine cable section.

This project would also include a new substation which would be built and tied into these circuits to serve the increasing power requirements on the Sechelt Peninsula. This new substation would eliminate the need for an additional 230 kV transmission circuit from Cheekye to the Sechelt Peninsula, which would otherwise be required if the Cheekye-Dunsmuir project were not built.

TABLE 3-1

CHEEKYE-DUNSMUIR
500 kV TRANSMISSION COSTS

(Preliminary Estimates)
(1977 price levels)

		Cost ($1,000)
1.	Cheekye-Dunsmuir transmission circuits (two circuits, plus spare phase from Nelson Island to Dunsmuir)	
	(a) Overhead portion	108,057
	(b) Submarine cable portion	137,065
	Total	245,122
2.	Cheekye Loop - Loop 5L42 circuit into Cheekye Substation	2,841
3.	Cheekye Substation - Terminate four - 500 kV lines	10,860
4.	Malaspina Substation - Terminate four - 500 kV lines, and install associated reactors	12,110
5.	Cable pothead locations	16,220
6.	Dunsmuir Station - Terminate two - 500 kV lines, install reactors, provide step down transformers	27,100
7.	Microwave Facilities	1,052
	Total Project Cost	315,305

3.2 LOAD-RESOURCES BALANCE OF TRANSMISSION PLAN

The existing sources of power supply serving Vancouver Island and a forecast of future loads are shown in Exhibit 3-1. The total dependable capacity of the existing power supply will be 1460 MW by 1979, as summarized in Table 2-1. In the winter of 1983/84, the forecast peak load is expected to be 1535 MW, which will exceed installed dependable capacity, and a new source of power supply will be required.

The first circuit of the 500 kV Cheekye-Dunsmuir transmission project is therefore scheduled for service in October 1983. Although this first circuit will have a rated capacity of 1100 MW, its contribution to total dependable capacity serving Vancouver Island will be only 320 MW, due to the large margin of reserve capacity required to support possible forced outages of this circuit. The second 500 kV circuit would be required then by October 1986, as shown in Exhibit 3-1. These two circuits together would contribute a total dependable capacity of 1440 MW, and would be able to serve all load growth on Vancouver Island until 1995.

The feasibility of advancing the in-service date of the first circuit to November 1982 is also being studied, in order to serve new industrial load growth on Vancouver Island which was not included in the forecast. The study of this advanced in-service date is beyond the scope of this report however.

3.3 TECHNICAL FEASIBILITY OF 500 kV AC CABLES

To date, no 500 kV ac submarine cables have been placed in commercial service, but land cables of this voltage class have been successfully placed in service in the United States (Grand Coulee), and in Japan. For the Mica project, a 500 kV ac cable facility for transmission between the underground powerhouse and the surface switchyard was technically acceptable but rejected because of a more economically

VANCOUVER ISLAND
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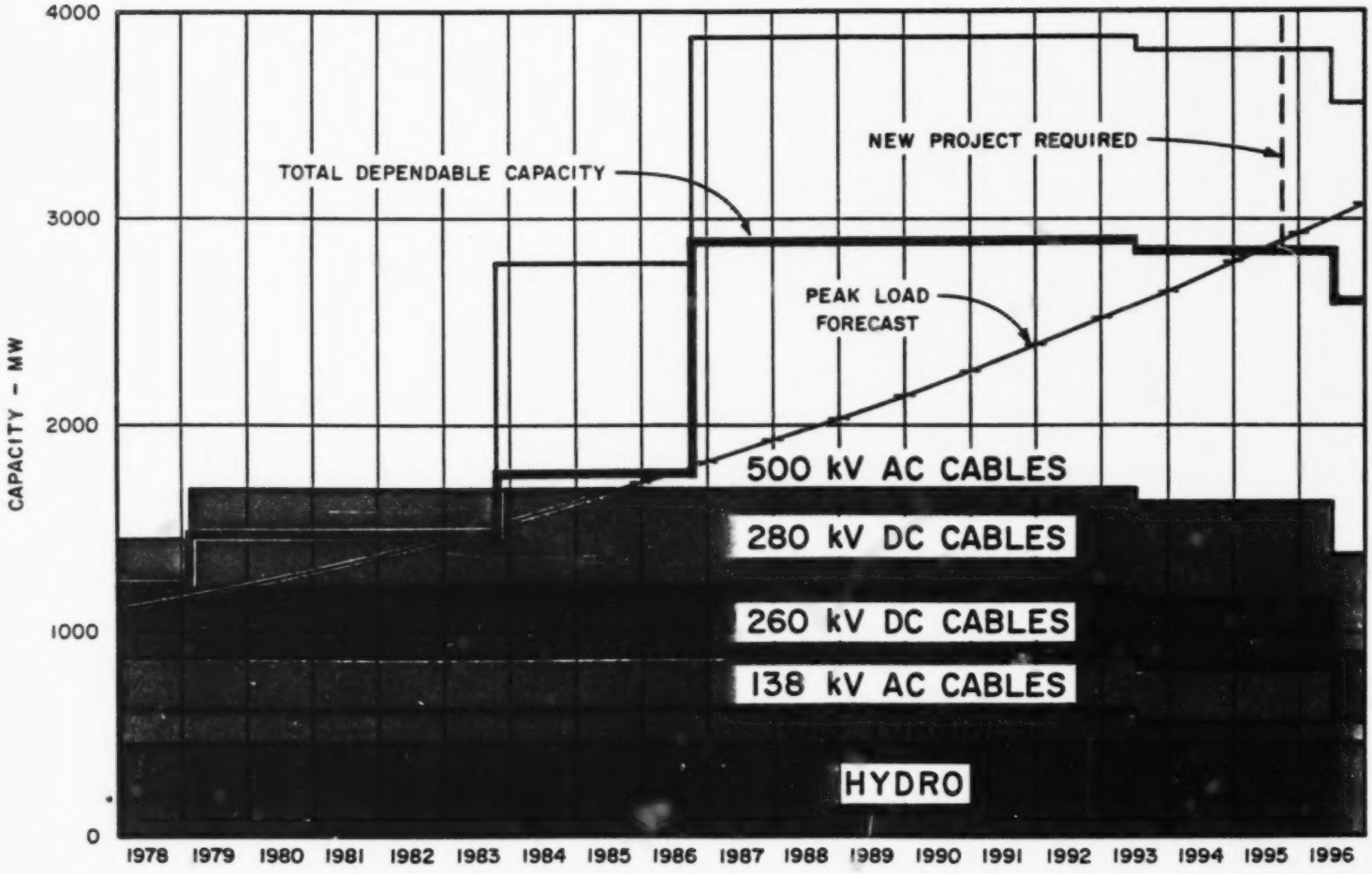


EXHIBIT 3-1

3.3 TECHNICAL FEASIBILITY OF 500 kV AC CABLES - (Cont'd)

attractive and flexible facility of SF6 bus at 500 kV ac. However, these land installations are quite short compared to the 30-39 km route for the submarine crossings in the Cheekye-Dunsmuir study area.

High voltage submarine cables have been successfully laid in water depths in excess of that to be encountered in crossings between the Sechelt Peninsula and Vancouver Island. The Sardinia-Corsica-Italy mainland 200 kV dc submarine crossing went to a depth of 480 m and the Skagerrak crossing from Norway to Denmark at 250 kV dc was successfully laid in a depth of 550 m. For the B.C. Hydro 500 kV submarine cable project, the maximum depth will be approximately 400 m, whereas the existing 280 kV dc submarine cable installations across the southern Strait of Georgia have been laid at a maximum depth of 250 m. However, at 500 kV ac, and for the ampacity ratings required and water depths to be encountered, B.C. Hydro's 500 kV ac cable will be of larger diameter and higher unit weight than other submarine cables installed to date, and will introduce more difficult mechanical design problems than those experienced on previous high voltage submarine cable installations.

A critical requirement in the electrical design of the cable is the determination of the necessary cable insulation strength (BIL) to withstand the switching surges and lightning surges that can occur on B.C. Hydro's electrical system. A transient network analyzer study is required to determine specific values for such transient phenomena. B.C. Hydro consulted several firms having the expertise and simulation facilities necessary to investigate electromagnetic transients: General Electric, Westinghouse, IREQ (Quebec Hydro), CEGB (England) and CESI (Italy). Subsequently, IREQ was chosen as the most suitable facility for these studies and B.C. Hydro engineers spent 5 weeks conducting studies of the proposed 500 kV Cheekye-Dunsmuir transmission on the IREQ simulator in late 1977. The results of these studies show what electromagnetic transients can be expected on this transmission

system and form the basis of the specification of the cable insulation strength and the cable insulation tests. The circuit overvoltages observed in the IREQ studies did not exceed the strength of cable insulation designs offered by major cable suppliers during discussions with them in early 1977.

Technical discussions have been held with Industrie Pirelli of Italy and Standard Telefon og Kabelfabrik A/S (STK) of Norway. Both Pirelli and STK are deemed to have the technical design expertise and manufacturing facilities to successfully undertake a 500 kV ac submarine cable project. Pirelli have one of the world's foremost laboratory facilities devoted to basic research on high voltage cable systems. At the CESI test facility in Milan, Pirelli have now successfully completed a long-term accelerated life test of 26 months duration on a prototype 750 kV self-contained, oil-filled cable complete with stop joint, normal joint and terminal accessories. Half of the cable in this test setup is basically a submarine cable type construction (i.e. large bore internal oil duct, segment type stranded conductor and reinforced lead sheath) and was manufactured in Pirelli's submarine cable plant at Arco Felice. Power factor measurements throughout the 26-month test program were very satisfactory, and indicate insulation stability. Since the stop joint, normal joints and terminals incorporated in this 750 kV cable system test program are also similar in construction to accessories contemplated by Pirelli for B.C. Hydro's 500 kV cable project, the results obtained in the 750 kV cable test program provide good assurance of reliable electrical performance for Pirelli's proposed 500 kV cable system designs. In addition, Pirelli are now proceeding with the design development for a 1100 kV self-contained oil-filled cable, and will shortly be manufacturing a 300 m prototype length of this 1100 kV land cable for testing at ENEL's 1000 kV project test facility at Suvereto. These achievements in developing self-contained oil-filled cables for operation at 750 kV to 1100 kV make Pirelli the leader in extra high voltage cable development.

3.3 TECHNICAL FEASIBILITY OF 500 kV AC CABLES - (Cont'd)

STK also has extensive experience in the manufacture and installation of submarine cables. This firm manufactured and laid their first 300 kV ac submarine cable in 1959. Noteworthy recent achievements are: (1) the manufacture and installation in 1975 of a 420 kV ac self-contained, oil-filled submarine cable circuit at a maximum depth of 220 m (the ampacity rating of this cable is 1250 A); and (2) the planning and execution of a bipolar ±250 kV HVDC 500 MW submarine transmission connection between Norway and Denmark known as the Skagerrak project. This project, consisting of two 250 kV dc solid type cables, route length 130 km, maximum depth 550 m, constitutes a major achievement in high voltage submarine cable installations. A development contract for the Skagerrak project was awarded STK in 1972 followed by a contract in 1973 for the supply and installation of two cables. These cables were laid successfully in 1976 and 1977. STK is also presently manufacturing 420 kV ac submarine cable for a crossing of the outer Oslofjord, with a route length of 11 km and a maximum depth of approximately 310 m; these cables are planned for installation in 1978/79.

Following technical discussions in June/July 1977 with Industrie Pirelli of Milan, Italy and Standard Telefon og Kabelfabrik A/S (STK) of Oslo, Norway, tendering specifications were prepared for a development program covering the design of 500 kV submarine cables of the ampacity rating required for this project. This program includes rigorous mechanical and electrical tests to demonstrate that such designs, derived from experience on existing high voltage submarine cable installations, would perform satisfactorily under the conditions to be encountered on this specific 500 kV project. The design and electrical and mechanical testing of two types of splices are also included in the development program specifications. These are: (1) a factory flexible splice for fabrication in the manufacturing plant to join two production lengths of cable before the armouring operation so

that armour is applied continuously through the splice locations; and (2) a field repair splice to be employed during on-site repairs, either during installation or subsequent service operation, where cable must be cut and therefore both cable and armour will require restoration within the splice. The cable and the factory flexible splice will be required to pass the specified development program tests before an award of a supply and install project contract is made. Development of the field repair splice will be left until after the award of the contract.

In response to a public tender call, tenders for the development program outlined next above were submitted by Mitsui and Co., (representing a consortium of two Japanese cable manufacturers - Furakawa and Sumitomo), Industrie Pirelli, and Standard Telefon og Kabelfabrik (STK). Following intensive study and review of the above tenders with particular emphasis placed on extensive experience in the manufacture and installation at large depths of high voltage submarine cables for ac and dc system applications, development contracts for the Cheekye-Dunsmuir 500 kV submarine cable project were awarded to Pirelli and STK in February 1978.

To ensure the achievement of coordination of various aspects of the development programs at an early stage of these contracts, additional technical discussions were held in Milan and Oslo with Pirelli and STK respectively in April 1978. These discussions confirmed that both Pirelli and STK were committing their resources adequately to the development contracts. On 9 May 1978 Pirelli reported on preliminary electrical tests conducted at CESI on an unarmoured sample of their 500 kV cable design including a factory splice. Prior to electrical testing, the sample was subjected to a bending test around a cylinder of 6 m diameter. The following voltages were successfully applied:

3.3 TECHNICAL FEASIBILITY OF 500 kV AC CABLES - (Cont'd)

(a) AC Voltage

450 kV	24 hours
580 kV	24 hours
680 kV	24 hours

(b) Impulse (3/55 μs waveform), Conductor Temperature 90°C

Ten shots negative polarity followed by 10 shots positive polarity at each of the voltage levels: 1400 kV, 1500 kV, 1600 kV, 1700 kV, 1800 kV and 1900 kV. After successful withstand of 10 shots of 2000 kV negative polarity, the test sample broke down at the first shot 2000 kV positive polarity. The failure occurred on the cable rather than within the splice. Similar preliminary tests were scheduled by STK about the end of May 1978. The Pirelli test results provide solid evidence that the basic electrical performance of their 500 kV cable and flexible splice designs are satisfactory.

Assurance of a firm in-service date for the submarine cable project is necessary in developing the plan for Vancouver Island's power supply. A staged project schedule covering the complete 500 kV submarine cable program has been prepared. The critical stages of the program are sequenced to ensure successful achievement of one stage prior to commitment to a further stage. The schedule for the entire cable program consists of three separate stages:

	Time Allowance
Stage 1 - Design, development, performance of electrical and mechanical tests on prototype cable samples and splices to specific project requirements including design of laying equipment and accessories	15 months

3.3 TECHNICAL FEASIBILITY OF 500 kV AC CABLES - (Cont'd)

Allowance for negotiation of contract for Stage 2 and Stage 3 programs	7 months
Stage 2 - Performance of a sea trial on a prototype length of 500 kV cable including flexible factory and field repair splices. Laying machinery designed for Stage 3 contract installation to be employed on sea trial	12 months
Stage 3 - Manufacture and installation of one complete 500 kV submarine cable circuit comprised of four single conductor cables	36 months
Elapsed Time (award of Stage 1 to in-service date)	70 months

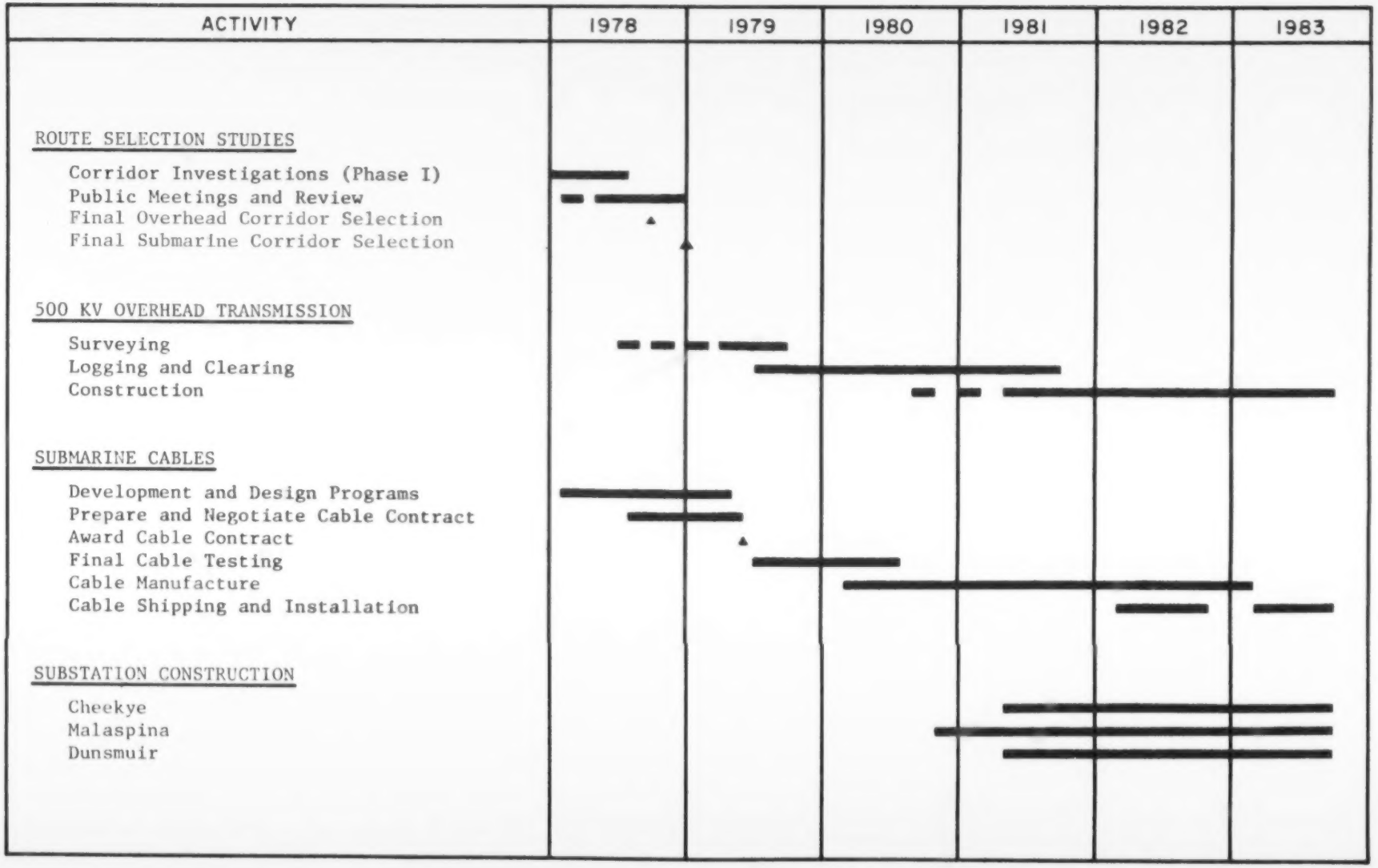
Negotiation of the contract for Stages 2 and 3 of the cable program in conformance with the above schedule requires a decision on final contract cable routes by late 1978 if the sequencing of Stage 2 and Stage 3 work activities is to be maintained. The project schedule for these transmission cables is summarized in Exhibit 3-2.

Recently requests have been received from large industrial customers on Vancouver Island for contract allocations of additional power for expanding their operations. Since contracts for additional power cannot be committed until the Cheekye-Dunsmuir transmission circuit is available for service, a full review of project schedules is underway to determine feasibility of advancing the in-service date. Providing the development contracts qualification tests are completed satisfactorily as presently scheduled and if additional overlapping of Stage 2 and Stage 3 project activities is accepted, a target in-service date of 30 November 1982 for the cable project is possible. To maintain the option of a target 1982 in-service date, it is mandatory that the

EXHIBIT 3-2

CHEEKYE - DUNSMUIR 500 kV TRANSMISSION

PROJECT SCHEDULE



3.3 TECHNICAL FEASIBILITY OF 500 kV AC CABLES - (Cont'd)

decision on final contract cable routes be made by early September 1978 so that the contract tender documents can be issued not later than the end of October 1978.

3.4 ROUTE SELECTION

The final selection of a route for a major transmission line is made only after extensive study of alternative routes. To carry out these studies B.C. Hydro usually engages independent consulting firms to examine alternative transmission routes and evaluate their environmental impacts.

These studies are carried out in two phases which are consistent with the aims of the Environment and Land Use Committee's Guidelines for Linear Development. In the first phase, the consultant studies the possible impacts of the proposed transmission line on a regional basis, defines possible alternate corridors for the transmission line, and finally recommends one or several preferred corridors.

After the consultant has submitted a report on the first phase studies to Hydro, the report is made available to government agencies and the public. Hydro then seeks comments from government agencies and the public. When all the meetings have been held, a decision is made on which corridor will be used for the transmission line and the consultant is asked to study that corridor and to recommend a route for the transmission line within it. In this second phase of the studies, the consultant is also asked to consider in detail the possible impacts of the transmission line in that corridor and to recommend possible mitigative measures.

3.4 ROUTE SELECTION - (Cont'd)

After an evaluation by B.C. Hydro of consultant's proposals, Beak Consultants Ltd. were retained to carry out the route location studies for the Cheekye to Dunsmuir 500 kV transmission line. Beak are now working on the first phase of this study. During the course of these studies, it became evident that the availability of information for the submarine portions of the study area was significantly lagging behind that for the overhead section. Beak were therefore requested to split the study report into two volumes, so that the completed mainland studies could be made available to the public as soon as possible. Volume 1, which covers the mainland portion of the study area from Cheekye substation to the east coast of Malaspina Strait, was finished in mid-1977 and has been distributed to the public. Volume 2, which will cover the portion of the study area from Malaspina Strait to Dunsmuir substation, is expected by the fall of 1978.

(a) Overhead Transmission Line Corridors

The transmission line corridor recommended by the consultant between Cheekye substation near Squamish and Cape Cockburn on Malaspina Strait is shown on Exhibit 1-1 (page 1-3). The physical terrain in this part of the study area can be conveniently discussed in two separate sections. The section between Cheekye substation and Sechelt Inlet is rough mountainous country in which snowslides and avalanches are common and long span overhead water crossings will be required. Because of these problems, only one routing has been recommended by Beak. This corridor is generally considered to be feasible by B.C. Hydro engineering staff, but additional technical studies and surveys will be required to locate a specific right-of-way.

The section between Sechelt Inlet and Cape Cockburn is much less rugged. On the Sechelt Peninsula the consultants have recommended three corridors for consideration, although they do state a preference for the most southwesterly of the three routes.

3.4 ROUTE SELECTION - (Cont'd)

In addition to the transmission line, a new 500/138 kV substation would be built on the Sechelt Peninsula. This substation, which would be tied into the Cheekye-Dunsmuir circuits, will be required to serve the increasing power requirements on the Sunshine Coast. While the location of the substation would depend on the route chosen, it will require a suitable section of flat land and would be tied into the existing 138 kV circuits which run between Sechelt and Powell River.

Routing of the sections of the overhead line between Malaspina Strait and Dunsmuir substation will depend on the routes chosen for the submarine cable. A preferred corridor will not be known until Beak has completed the Volume 2 report.

(b) Submarine Cable Routes

The environmental impacts of feasible cable routes are presently under study by Beak. Advice on technical constraints which will affect routing is being provided by Hydro.

Bottom conditions are a critical factor in choosing a cable route. The optimum seabottom on which to lay the cable is smooth sand or silt. A smooth rock bottom is acceptable as long as it is in water that is deeper than that in which anchors or trawling nets are likely to be deployed. On a rock bottom in comparatively shallow water where anchors or trawling nets may snag the cable, expensive submarine rock blasting could be required to bury the cables. Cables across irregular steep outcroppings of rock are subject to a number of hazards which could reduce the cable's life and dependability. Cables suspended over sharp rock outcroppings are subject to eventual sheath failure due to abrasion and fatigue and also are easily snagged by anchors or trawls.

3.4 ROUTE SELECTION - (Cont'd)

For a multiple cable project such as this, the availability of acceptable bottom conditions over a sufficient width of cable corridor is an essential element in route selection. The allowances for navigation course deviations during cable laying to avoid crossover of adjacent cables, the depth of water, the length of cable route, the equipment available, and the procedures developed to carry out repairs in the event of damage to operating cables are all factors which collectively determine the minimum cable spacing to be employed. Based on these factors, a minimum corridor width of approximately 2800 m will be required for the seven cables ultimately to be installed (three cables per circuit plus a spare cable) for this project.

It will also be desirable to limit the maximum span of submarine cable crossings, since long crossings would probably require splices, which could reduce the reliability of the cable and its power supply. The maximum unspliced cable length that can be produced with existing manufacturing facilities is about 16 km. Longer cable crossings requiring factory splices have not been ruled out however, and a determined effort will be made in the cable development programs described in Section 3.3 to improve the design and technical reliability of cable splices.

Exhibit 1-1 shows some of the cable routes under study, although it does not show all of the possible alternatives which are currently under study. The direct Texada Island-Dunsmuir route appears to be the most attractive of the routes shown from an environmental viewpoint. However, this route would require a 30 km long cable crossing with splices in the middle. The Texada Island-Lasqueti Island-Qualicum Beach route would have shorter cable crossings without cable splices and would offer technical advantages, but at the cost of greater environmental and social

3.4 ROUTE SELECTION - (Cont'd)

impact. Many other routes are also being studied, and will be described in the Beak Phase I Volume II report when it is completed.

3.5 ENVIRONMENTAL IMPACTS OF TRANSMISSION

The major environmental impact of the Cheekye-Dunsmuir transmission project would probably be the visual impact of the lines themselves. Along many sections of the transmission route, the cleared transmission corridor with towers and lines could present an unwelcome intrusion on the natural landscape. B.C. Hydro recognizes this problem, and will take care to avoid such impacts by selecting the least obtrusive transmission corridor wherever it is possible to do so at reasonable additional cost and without significantly endangering the security or safety of power supply. Unfortunately, it will be impossible to find a transmission route that completely avoids all adverse environmental impacts. The planning process must therefore attempt to minimize such impacts within the constraints of acceptable cost and security of power supply.

The study of alternative transmission corridors is currently being conducted by Beak Consultants. A description of specific environmental impacts of alternative transmission corridors will not be attempted in this report, since these studies are not yet complete, and will be summarized in detail by Beak. Therefore, the discussion here will be restricted to general environmental concerns common to all the alternative routes of the Cheekye-Dunsmuir transmission project. These general concerns fall into three categories: the effect of EHV electromagnetic fields; the possible toxicity of submarine cable oils; and the use of herbicides for transmission right-of-way clearing.

3.5 ENVIRONMENTAL IMPACTS OF TRANSMISSION - (Cont'd)

(a) EHV Field Effects

Some concern has been expressed at recent public meetings about the environmental effects of electromagnetic fields associated with extra high voltage (EHV) transmission lines. The possible effects from EHV transmission lines include the production of ozone, audible noise, radio and TV interference, low voltage induced shocks, and biological effects of electric fields.

Ozone gas production has been accepted as being insignificant. A slight crackling noise may be audible underneath EHV transmission lines, particularily in rainy weather, due to corona discharge. Audible noise from an EHV transmission line is almost exclusively a foul weather phenomenon. Low voltage induced shocks may result from contact with ungrounded metal objects near the lines. Radio and TV interference and the possibility of induced shocks can be essentially eliminated by proper design and maintenance of the lines and grounding of nearby metal objects. The question of biological effects is more difficult to define.

A great deal of research has been conducted to determine the possible biological effects of EHV electric fields, and B.C. Hydro engineers are maintaining an up-to-date review of the scientific literature on this subject. Based on the generally accepted scientific research performed to date, as reported in this literature, there appears to be no harmful biological effect due to electromagnetic fields associated with 60 cycle 500 kV transmission lines. A direct quote from a recent EPRI article* is typical of the scientific community's attitude toward this subject:

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* See "Controversy Over High-Voltage Effects" by C. Comar, Director of Environmental Assessment Department, Electric Power Research Institute, EPRI Journal No. 5 for June/July 1977.

"Drawing on experience and observation, the immediate assessment shows that all living organisms have always been exposed to natural electric and magnetic fields from atmospheric electricity and magnetism; people are exposed to fields from household appliances without apparent effect; no harm has been observed from transmission lines up to 765 kV in the United States since 1969; no effects have been seen in studies of U.S. linemen who worked on 365 kV lines; and animal experiments so far have demonstrated no effects in the range of normal exposures found under transmission lines. From this experience there is good reason to believe that exposures to electric fields from transmission lines up to 765 kV would not produce harmful biological effects."

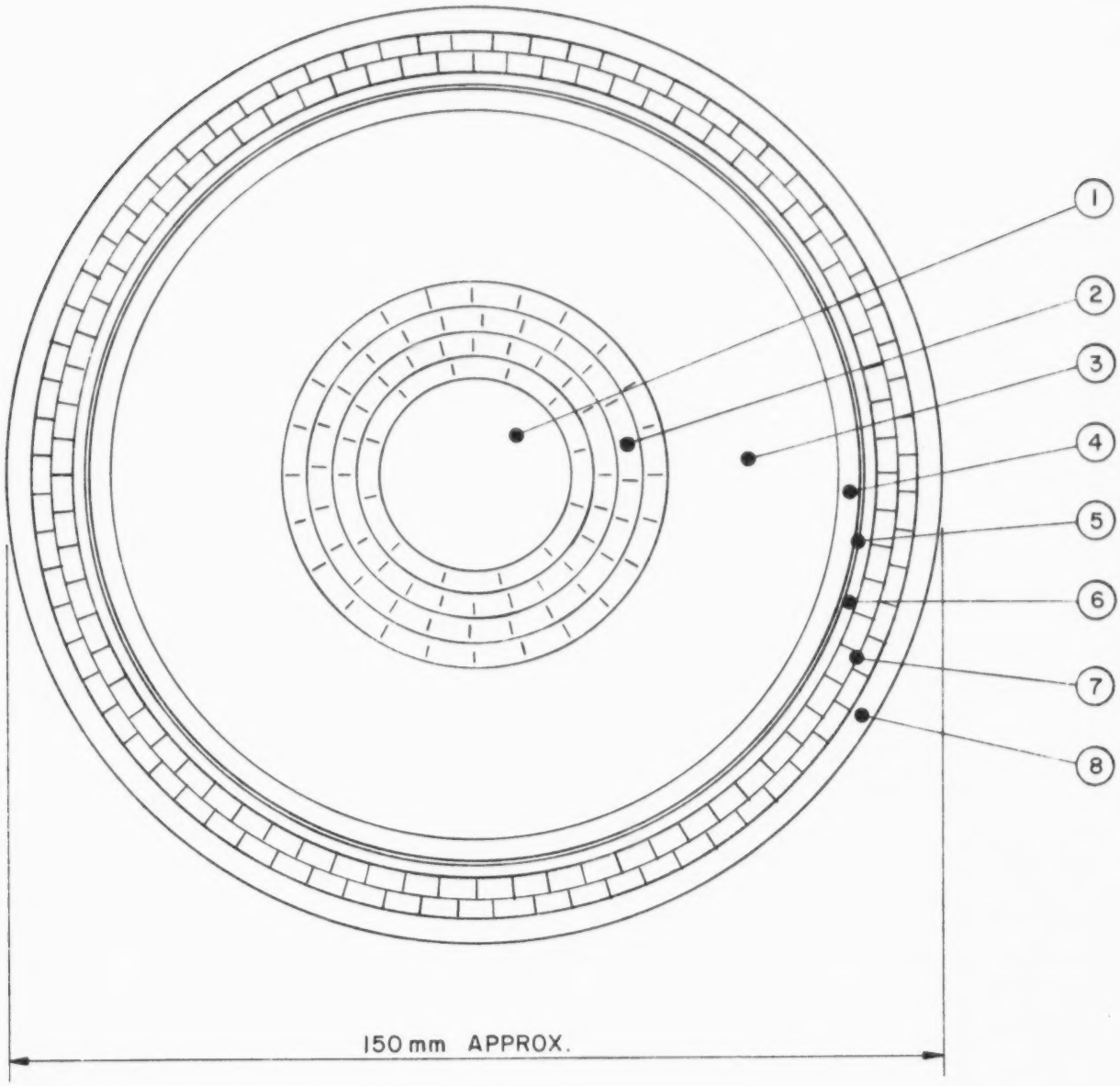
B.C. Hydro has already operated 500 kV transmission lines in many parts of British Columbia since 1968 without any noticeable health hazard due to EHV field effects.

(b) Cable Oils

The submarine transmission cables planned for the Cheekye to Dunsmuir 500 kV transmission project will have a hollow core, filled with oil for insulation. If these transmission cables are damaged, small quantities of this cable oil could leak out, and there has been some concern that such an oil leakage could have harmful environmental effects.

A cross-section of a high voltage submarine transmission cable similar to the proposed 500 kV Cheekye-Dunsmuir cables is illustrated in Exhibit 3-3. The central copper conductor in this cable will be made up of shaped copper wires wound to form a tube with oil impregnated paper wrapped around the conductor to provide insulation. The hollow core is filled with oil, and very low viscosity oils must be used to ensure positive oil pressure to all

500 kV SUBMARINE TRANSMISSION CABLE
TYPICAL CROSS SECTION



1 OIL CORE
2 CONDUCTOR, COPPER
3 INSULATION, IMPREGNATED PAPER
4 LEAD SHEATH
5 REINFORCING TAPES
6 ANTI-CORROSION JACKET
7 ARMOURING WIRES
8 JUTE COVERING

of the cable insulation under all electrical loading conditions, and simultaneously keep the hydraulic pressure within practical limits. Oils with these insulating and low viscosity properties which are used in electric cables are not polychlorinated biphenyls (PCB) or related derivitives.

The transmission cables will be totally sealed and there will be no leakage of oil or other materials under normal operation. In the unlikely event of cable damage caused by anchor snagging or abrasion, small quantities of cable oil could leak out. If a cable were to rupture completely, about 35 barrels of oil could be released in the first 2 hours, and after that cable oil flow would be progressively reduced over the next 30 hours. After this period the thermal transient would be completed, and the oil flow adjusted to approximately 1 gallon per hour. This flow rate of 1 gallon per hour would then be maintained until the ruptured cable ends could be recovered and capped. Based on previous experience with cable damage on existing submarine cable installations, a severed cable should be capped within a 14-day period.

Cable insulating oils are lighter than water and have viscosities similar to water. They are virtually colourless and essentially insoluble in water and do not result in water pollution problems. Because of their low specific gravity and insolubility, any leaking oil would rise rapidly to the surface, where the low viscosity causes rapid dispersal into a thin film which would evaporate readily under the action of wind and waves.

Environment Canada have performed bio-assay tests on one of the oils which may be used with the 500 kV cables. This oil is a linear decylbenzene belonging to the alkylate family (a hydrocarbon), with the trade name of Voltoil 10. Environment

Canada found that concentrations in excess of 10 percent are required to be toxic to juvenile coho salmon. Such high oil concentrations could never be reached due to cable oil leakage in the relatively open waters of Georgia and Malaspina Straits. The other oil which may be used with the 500 kV cables is a mineral oil (also a hydrocarbon).

At this time, B.C. Hydro is in the process of commissioning additional bio-assay tests and chemical analyses of the cable oils by independent organizations in order to confirm their safety.

(c) Transmission Route Clearing

To ensure reliable service of power supply, regular inspection and maintenance of transmission lines and their rights-of-way is essential. Tall trees and high brush must be removed or pruned along the entire length of the transmission system rights-of-way to prevent branches from touching or falling on the power-lines, causing interruptions in service. In addition, heavy brush must be cleared to permit access to lines, poles and towers to minimize the time required to locate and repair any trouble.

The original clearing of Hydro's rights-of-way is carried out by heavy equipment such as bulldozers, where soil stability is such that their use will not result in soil erosion. In other areas subject to erosion, the clearing is carried out by hand-held equipment.

Subsequent maintenance is effected by brush mowers, mechanical flails, small bulldozers, hand-held equipment and herbicides. Herbicide treatment is used in areas of difficult access, rugged terrain, extremely rapid re-growth of vegetation or where desired by the owner of the land on which the rights-of-way is located. One of the goals of vegetation management on rights-of-way is to encourage the establishment of low growing species such as salal, blackberry and grasses which require little or no maintenance.

In its use of herbicides, Hydro is guided by federal and provincial legislation enacted to protect people and wildlife. Federal statutes include: the Pest Control Products Act, the Fisheries Act and the Food and Drug Act. Provincial Statutes include: the Wildlife Act and regulations under the Pesticide Control Act.

Before B.C. Hydro undertakes any specific herbicide program, it is first required to make application in writing to the Administrator, Pesticide Control Act. The Administrator then presents the application to the Pesticide Control Committee. The committee has as its chairman the Administrator, and members are from the:

1. Provincial Ministry of Agriculture.

2. Provincial Ministry of the Environment.

3. Provincial Ministry of Forests.

4. Provincial Ministry of Health.

5. Provincial Ministry of Recreation and Conservation (Fish and Wildlife).

6. Federal Environmental Protection Service.

The members of this committee are specialists in their own field and have the responsibility of determining the terms and conditions under which a herbicide program can be safely executed. The restrictions imposed by these regulatory agencies are scrupulously observed. Two of the conditions required by regulation and this committee are:

1. That a certificated Pesticide Applicator in the Industrial Vegetation Control category be present on the site during the course of all herbicide treatment programs. The examination for this certificate is conducted by the Ministry of the Environment under the authority of the Administrator, Pesticide Control Act.

2. That only materials registered under the Pest Control Products Act, a Federal Statute administered by the Department of Agriculture in Ottawa, are used. Before a product is registered this agency requires full documentation of scientific and experimental data to permit a full and fair evaluation of the effectiveness and safety of the material.

The herbicides used by B.C. Hydro for powerline maintenance, which include 2,4-D; 2,4,5-T; and picloram (Tordon), have all been thoroughly tested, and shown by federal and provincial government experts and respected scientists to be safe and harmless to man, domestic animals, wildlife, birds and fish when used in accordance with manufacturers' label instructions and government regulations.

SECTION 4.0 - ALTERNATIVE TRANSMISSION SYSTEMS

4.1 ALTERNATIVES STUDIED

Five transmission systems for supplying power to Vancouver Island after 1983 have been examined. Different routes, one entirely overhead and four requiring submarine cables, were assessed; two ac design voltages, 230 kV and 500 kV were studied; and the merits and costs of direct current (HVDC) transmission were considered.

The alternatives studied were:

1. 500 kV ac, Cheekye-Dunsmuir, overhead and submarine sections.

2. ±450 kV dc, Cheekye-Dunsmuir, overhead and submarine sections.

3. 500 kV ac, Kelly Lake-Dunsmuir, entirely overhead transmission.

4. 500 kV ac, Arnott-Vancouver Island Terminal, overhead and submarine sections.

5. 230 kV ac, Cheekye-Dunsmuir, overhead and submarine sections.

A detailed description of the recommended plan, Alternative 1 above, was given in Section 3.0. The remaining alternatives are discussed in the sections that follow.

4.2 COST AND TECHNICAL COMPARISON OF AC VERSUS DC

High voltage direct current (HVDC) transmission does not become economically attractive unless the cost of similarly-rated alternating current transmission is higher than normal per kilowatt of

power being transferred. This will usually occur only when transmission distances are exceptionally long or when cable must take the place of overhead transmission because right-of-way is unavailable or water crossings are too extensive to be spanned. Much of the cost of an HVDC system is in the converter stations required at each end of the dc circuits. The cost per kilowatt of these stations goes down as the power rating goes up, and the costs of dc cables and overhead lines are usually less than their similarly-rated ac counterparts.

The cost comparison of ac and dc transmission which follows shows that, the above considerations notwithstanding, HVDC is not an economical alternative for this project. There are also technical problems with such a scheme. The principal difficulty is that the Vancouver Island power system has a low fault level, considerably below what would be required for successful HVDC operation. The fault level can be increased only by installing synchronous condensers as was done at the Arnott-Vancouver Island Terminal HVDC Project. In addition, an HVDC system generally has a power factor of about 0.85 at the receiving end. This means that for every kilowatt of power received, 0.62 kvar of reactive power must be generated, or for a 2200 MW system, 1364 MVAR. Fortunately, this reactive power requirement can be partly met by the synchronous condensers and partly by the harmonic filter shunt capacitors. Nevertheless, the necessity to increase the fault level and improve the power factor contributes to the expense and complexity of the HVDC alternative.

The technical reliability of an ac scheme is believed to be better than could be expected of a dc scheme because of the complexity of the HVDC converter stations. If the Cheekye-Dunsmuir project proceeds it will be the principal source of power to Vancouver Island for many years and the importance of reliability must not be overlooked in any comparison of alternatives.

4.2 COST AND TECHNICAL COMPARISON OF AC VERSUS DC - (Cont'd)

Because of the high dc voltage level required to make the dc cable technically equivalent to the ac cable, there is no cost advantage in building overhead dc transmission between Cheekye and the sea coast. In fact, it is estimated that the 450 kV dc overhead costs will be almost identical to the 500 kV ac overhead costs. The dc alternative therefore differs from the ac in that the new 500 kV substation to be located on the Sechelt Peninsula would now also become an ac/dc converter station as would the planned 500 kV Dunsmuir Substation. The transmission between these two stations would now consist of five 30 to 39 km long undersea dc cables and up to 32 km of overhead dc transmission line. The dc transmission system would operate as two bipolar circuits each at ±450 kV.

In comparing costs of the ac and dc alternatives, all costs common to both alternatives, such as looping circuit 5L42 into Cheekye, providing step-down transformation at Malaspina, and providing 500 kV ac switching at Cheekye and Dunsmuir have been excluded. The results of the cost comparison of ac versus dc in 1977 dollars excluding common costs are given below:

	Cost ($1,000)
HVDC	
Cable: 5 x 30 km x $386,800/km	58,020
Overhead: 2 x 150 km x $360,000/km (both ac and dc sections)	108,000
Converter Stations 2,200,000 kW x 2 x $38/kW	167,200
Synchronous Condensers	33,800
Total	$367,020
AC	
Cable: 7 x 30 km, detailed design estimate	$136,350
Overhead circuits	108,000
Reactors	19,400
Total	$263,750

4.2 COST AND TECHNICAL COMPARISON OF AC VERSUS DC - (Cont'd)

In this comparison the capital cost of the dc alternative is 39 percent higher than the ac alternative. In addition to the above capital costs, the operation and maintenance costs of the HVDC system, with its valves, control schemes, filters, and synchronous condensers, would be considerably higher than that of the ac system. The cost of power losses for the dc system would also be significantly higher. In view of the cost of the dc alternative, further consideration of this alternative is not recommended.

4.3 500 kV OVERHEAD TRANSMISSION FROM KELLY LAKE TO DUNSMUIR VIA BUTE AND KNIGHT INLETS

(a) Description of Route

In December 1972 a preliminary study was made of possible routes from Kelly Lake Substation near Clinton to Vancouver Island, including the Homathko River-Bute Inlet and the Klinakline-Knight Inlet routes.

A Kelly Lake-Dunsmuir 500 kV transmission system would consist of two 500 kV single circuit lines between Kelly Lake Substation and a new 500 kV switching station at Chilko Lake 202 km away. From Chilko Lake one circuit would be routed via the Klinakline River and Knight Inlet and one via the Homathko River and Bute Inlet with both circuits converging on a common right-of-way once more near Dent Island. The Knight Inlet circuit would be 285 km long and the Bute Inlet circuit 204 km. From Dent Island the two circuits would follow a common right-of-way 144 km to Dunsmuir Substation.

4.3 500 kV OVERHEAD TRANSMISSION FROM KELLY LAKE TO DUNSMUIR VIA BUTE AND KNIGHT INLETS - (Cont'd)

(b) Cost

The cost of this project is estimated to be $335.8 million in 1977 dollars including land, clearing, series capacitors and shunt reactors but not including switching costs at Kelly Lake and Dunsmuir. An additional cost of $18 million must be added to this alternative for a 230 kV transmission line from Cheekye to Sechelt to serve load growth in the Sechelt area.

This transmission proposal would tap power from a different point in the existing 500 kV transmission grid. It is therefore difficult to directly compare its cost with the alternatives where Cheekye Substation is the sending-end terminal. In order to compare these alternatives, the cost of the second 500 kV transmission line from Cheekye Substation to Kelly Lake Substation has been added to the alternatives which would tie into Cheekye. This Kelly Lake-Cheekye line would have a discounted cost of about $46 million. Resulting total costs of these alternatives are shown below:

Alternative	Total Cost ($ Million)	Relative Cost
Cheekye-Dunsmuir 500 kV ac	264	
plus Kelly Lake-Cheekye 500 kV	46	
	310	100.0
Kelly Lake-Dunsmuir 500 kV ac	336	
plus Cheekye-Sechelt 230 kV	18	
	354	114.2
Cheekye-Dunsmuir 450 kV dc	367	
plus Kelly Lake-Cheekye 500 kV	46	
	413	132.9

The cost of this overhead route from Kelly Lake to Dunsmuir is more than that of the Cheekye-Dunsmuir route. However, this route is not dependent upon submarine cable crossings, and it

would also have the advantage that if the Homathko hydro project was developed, little additional transmission would be necessary to integrate it into the system. Nevertheless, there are serious doubts about the technical feasibility and security of this route, as described in the next section.

(c) Technical Feasibility and Security

The Homathko River-Bute Inlet route traverses many sections which are particularly rugged and hazardous, making access difficult and line security questionable. Repair of a line in these sections in winter months would be totally dependent on the helicopter. Locating a route through this is made more difficult by the possible Homathko hydroelectric development. Additional location problems exist along Bute Inlet.

The Klinakline River-Knight Inlet route, although relatively more accessible and less hazardous, also has problem areas. In particular, there is a short section along Knight Inlet which consists of an almost vertical rock bluff extending from the water's edge up to an elevation of 750 meters with a few narrow benches for tower sites sufficient for one line.

In addition to the topographic hazards, there is a possibility of heavy icing and/or high winds occurring. In 1973, six weather stations were installed along the two routes. Wind speeds approaching 160 km/h have been recorded and icing equivalent to 2.5-cm radial thickness on a 2.5-cm diameter conductor was measured at the head of Knight Inlet. While this amount of ice is not serious, the probability exists of greater amounts occurring over the life of the line.

4.3 500 kV OVERHEAD TRANSMISSION FROM KELLY LAKE TO DUNSMUIR VIA BUTE AND KNIGHT INLETS - (Cont'd)

In summary, because of the short period of time over which weather data has been monitored, and because of the generally mild winter conditions experienced throughout British Columbia during this period, there is not sufficient basis to fully assess the ice and wind loading conditions along the two routes. Without further detailed field studies, the security of the lines along these routes must still be considered questionable.

In view of the uncertain technical feasibility and the additional cost, further consideration of this route is not recommended.

4.4 500 kV OVERHEAD AND SUBMARINE TRANSMISSION FROM ARNOTT TO VANCOUVER ISLAND TERMINAL

Consideration was also given to an alternative route parallel to the existing dc route between Arnott Substation and Vancouver Island Terminal (see Exhibit 1-1). While such a route has the technical advantage of much better ocean bottom conditions for the cable portion, it does have the following major disadvantages.

(a) Foreign Government Approvals

As 38 percent of the total cable route is within the territorial waters of the United States, applications would be required to the following American agencies for approval of this project:

1. Federal Power Commission.

2. U.S. Army Corps of Engineers.

3. Whatcom County, State of Washington (owner of seabed off Washington).

In the past the Authority obtained permits for the existing 138 kV ac cables and the Pole 1 dc cables through these agencies without great difficulty. However the legal procedures are time consuming and in the future additional obstacles in the form of public hearings, and intervention by pipeline companies and environmental groups must be allowed for. Recent advice from Seattle attorneys who have handled these matters for B.C. Hydro previously suggests a "best guess" of 30-36 months to process all the necessary applications.

The project scheduling must be arranged to avoid the possibility of having the project blocked in a foreign jurisdiction after the award of a contract for submarine cables. This licencing delay and the possibility of being unable to obtain project approval are serious impediments to this plan.

(b) Security

The increase in shipping activity in the Tsawwassen and Roberts Bank area is expected to continue and the probability of damage to cables due to this activity is bound to increase. Once cables are successfully laid on the sea floor they are immune to all the natural hazards experienced by overhead lines and are relatively more secure than overhead lines. They can, however, be damaged by ships' anchors and this risk is considerably greater in the Roberts Bank area than in Cheekye-Dunsmuir ocean corridors. Damage caused by ships' anchors could involve more than one cable and result in a power shortage on Vancouver Island for many months.

4.4 500 kV OVERHEAD AND SUBMARINE TRANSMISSION FROM ARNOTT TO VANCOUVER ISLAND TERMINAL - (Cont'd)

(c) Limitations of Transmission on Vancouver Island

The major load centres on Vancouver Island are located in the regions of Victoria, Duncan, Nanaimo, Campbell River and Port Hardy. The major power infeed to Vancouver Island is at Vancouver Island Terminal (VIT) near Duncan. All of the load centres northwest of Duncan are therefore dependent on the transmission lines running up the island from VIT for all power needs over and above those supplied by the generating stations in the northwest end of the Island.

Any disturbance on these transmission lines which causes one of them to trip out will result in a sudden redistribution of power flow over the remaining parallel circuits and, because of the length of this transmission (about 100 miles from Duncan to Campbell River), the generators in the northwest end of the island tend to "rock" or oscillate about their normal speed. As loading of the transmission increases, loss of one circuit constitutes a more severe disturbance and the generators oscillate more severely. If generator oscillations become too great, the generators will lose synchronism with the rest of the system and will no longer supply power. This loss of synchronism may also cause transmission protective relaying to "see" a fault or short circuit at some point between Duncan and Campbell River and the result will be further line tripping. A transmission system which splits apart like this is said to be unstable. The maximum power flow permissible on the transmission system for which stability will be maintained following the worst likely system disturbance is the stability limit of that transmission system.

In addition to the stability limit of a transmission system, there is also a current limit. As line loading increases,

the higher current causes the conductor temperature to rise. This in turn results in linear expansion of the conductors and an increase in conductor sag. Extreme overloading can cause conductors to sag to the point where they make contact with the ground resulting in a line trip-out. Less extreme overloading may be even more serious because the low conductor clearance to ground presents a serious hazard to anyone who might be on the right-of-way.

In view of the above stability and conductor clearance limitations, the maximum power flow presently permitted on the existing 138 kV lines from VIT to Nanaimo is nominally 350 MW. The new circuit scheduled for 1979 between VIT and Dunsmuir substations will increase this limit to about 480 MW.

These transmission limitations constitute a "bottleneck" north of VIT, and make proposals to bring additional power to Vancouver Island at VIT undesirable as long as the north Vancouver Island load continues to grow. By creating a second major power infeed point at Dunsmuir, this limitation of the Vancouver Island transmission system would be considerably alleviated.

(d) Loading of Transmission into the Metro-Fraser Valley Area

Feeding the majority of the Vancouver Island load from Arnott requires that all of this power must be transmitted into the Metro-Fraser Valley area from the Interior sources. Additional transmission would also be required between Ingledow and Arnott Substations. Both of these areas have severe transmission right-of-way limitations which make it difficult enough to supply the Metro-Fraser Valley area loads alone without having to supply Vancouver Island loads as well. By feeding the Island loads via

4.4 500 kV OVERHEAD AND SUBMARINE TRANSMISSION FROM ARNOTT TO VANCOUVER ISLAND TERMINAL - (Cont'd)

Cheekye-Dunsmuir, most of this right-of-way can be devoted to feeding Metro-Fraser Valley loads.

In view of the above disadvantages of scheduling, security, stability, and right-of-way limitations, further consideration of this route is not recommended.

4.5 230 kV OVERHEAD AND SUBMARINE TRANSMISSION FROM CHEEKYE TO DUNSMUIR

Preliminary studies show that it would be possible to serve Vancouver Island loads dependably up to about 1991 by means of a Cheekye-Dunsmuir transmission system designed for 230 kV operation instead of 500 kV. The principal advantage of this proposal would be a reduction in the capital cost of the project from $315 million for a 500 kV project to $248.5 million for a 230 kV project. However, each 230 kV circuit would have a capacity of only 500 MW, compared to 1100 MW for a 500 kV circuit. The average capacity cost of the two cable designs would therefore be $144/kW for the 500 kV design, and $248/kW for the 230 kV.

(a) Cable Design and Security

The major technical concern is the laying of the cable in the depths to be encountered along the feasible routes. This concern is not alleviated by reducing the design voltage to 230 kV. This is because at 230 kV, in order to achieve a 500 MW capacity, it is necessary to use the same copper conductor size as is being considered for the 500 kV design. Only the insulation thickness would be reduced; the outer cable sheathing and armour would remain essentially unchanged. The result would be a cable with only a slightly smaller diameter and slightly less weight. Diameter and weight are the major concerns when laying the cable.

Since a 230 kV cable design is only slightly smaller in diameter, no significant increase in cable length manufacturing capability can be expected. The splice requirements are therefore approximately the same for either 230 kV or 500 kV cable.

(b) 230 kV AC Operation

From an operational point of view, the lower voltage level would mean that, for the same power transfer, the losses would be higher.

(c) Transmission Routes and Impacts

Right-of-way on the ocean floor would be the same for both 500 kV and 230 kV lines. Overland right-of-way would decrease from approximately 125 m to 60 m width. The use of 230 kV cables would not result in further options in the choice of a submarine cable transmission line route.

Since 230 kV overhead transmission requires less right-of-way than 500 kV transmission and the transmission line towers are smaller, there would be some reduction in visual impact and in disruption of natural habitat. The initial impact of cutting a right-of-way through previously undisturbed areas would be much the same regardless of width, however, as would the visual impact of transmission in settled areas where no transmission previously existed.

The economic feasibility of this 230 kV transmission plan is examined in Chapter 6, on "Economic Comparison of Alternative Plans".

SECTION 5.0 - ALTERNATIVE VANCOUVER ISLAND GENERATION SOURCES

The feasible alternative generation sources on Vancouver Island are limited. There are still some undeveloped hydro sites, but they are too small and too few in number to supply more than one or two years of future load growth, although they may still be economical components of a broader program of power development. Nuclear power on Vancouver Island would be an economically attractive long-term power source, but a nuclear project could not be completed before 1991 due to the long lead time for licencing and construction, and would thus not be a feasible alternative to serve load growth during the next decade. The only remaining feasible power source for the 1980s would be fossil-fuel thermal plants on the island. Oil-fired gas turbine plants may be an economical source of future peaking capacity, but they would be too expensive to serve base loads. An oil-fired combined cycle plant would be more efficient, but would still be dependent on a high-cost, premium fuel. A coal-fired thermal plant on the Island would be the most practical and economical alternative power source, and could use either Comox, Hat Creek or East Kootenay coal. The foregoing alternative power sources are described in the following sections of this chapter.

5.1 VANCOUVER ISLAND HYDRO PROJECTS

An extensive survey of the remaining undeveloped hydro resources on Vancouver Island was carried out by B.C. Hydro during the period 1968-72 and summarized in the B.C. Energy Board Report of 1972. Three projects were identified in the B.C. Hydro Task Force Report of 1975 ("Alternatives, 1975 to 1990") as possibly suitable for development: the Kokish project, the Duncan Bay project and the Ladore expansion. Only these three hydro projects were considered in this study.

5.1 VANCOUVER ISLAND HYDRO PROJECTS - (Cont'd)

(a) Kokish Hydro Project

The Kokish project would be located on the Kokish River, near Beaver Cove, in the north of Vancouver Island. The project would include a dam at the outlet of Bonanza Lake and an 8 km long tunnel to a powerplant at tidewater near Beaver Cove. Bonanza Lake would be regulated as a storage reservoir, and the total developed head would be about 267 meters. The powerplant would contain a single generating unit of 162 MW and would produce 254 GWh average annual energy and 236 GWh firm annual energy. B.C. Hydro still has a Conditional Water Licence for this project, which was issued in 1959.

The estimated cost of this project, at October 1977 price levels, would be $81,200,000 for the dam, tunnel and powerplant, and $5,750,000 for the transmission facilities. These costs include all direct costs, contingencies, engineering, and B.C. Hydro overhead, but not interest during construction. The earliest feasible in-service date for this project would be July 1987.

The Kokish watershed is relatively undeveloped and much of the watershed around the reservoir area has been logged off. Bonanza Lake, which would be flooded by about 15 meters, may have future recreational potential, although current recreational use is limited. The Kokish River near the mouth supports an annual salmon run of about 2000 fish, primarily coho and pink salmon. Most of these salmon spawn in the Tsulton River, which joins the Kokish River a half mile above its mouth, and in the lower Kokish River below its confluence with the Tsulton. The potential salmon production of the Kokish River is estimated to be much higher however, based on historic records and on the high productivity of adjacent rivers such as the Nimpkish to the north. The exact

effect that the Kokish hydro project would have on salmon production is not known, although it is possible that mitigation measures, such as locating the powerplant directly on the coast, may reduce the impact on fisheries.

(b) Duncan Bay Project

The Duncan Bay hydro project would be located parallel to the existing John Hart hydro plant and would increase the power capacity of the Campbell River hydro system and bring the three-step river development closer to a hydraulic balance. The powerplant would have a 150 MW generating unit and would discharge directly into the ocean at Duncan Bay. The increase in energy production from the Duncan Bay-John Hart combination would be 272 GWh average annual energy and 184 GWh firm annual energy.

The estimated direct cost of this project is $88,900,000 at October 1977 prices. Transmission costs would be negligible since the project would be close to the existing Duncan Bay substation. The earliest feasible in-service date of this project would be July 1984.

The Duncan Bay project could have a serious impact on salmon spawning and sport fishing in the lower Campbell River. The existing John Hart plant has a relatively uniform and constant discharge into the Campbell River, which has enhanced salmon spawning in the river. An alternative to the Duncan Bay project would be to add additional generating capacity on the Campbell River adjacent to the existing plant (this alternative is the John Hart II project); however the total powerplant discharge from these two projects would fluctuate too much and could interfere with salmon spawning.

5.1 VANCOUVER ISLAND HYDRO PROJECTS - (Cont'd)

With the Duncan Bay plant located on the coast, it would discharge directly into the ocean, and the average discharge from the existing John Hart plant and spillway would be reduced, but would still be relatively uniform. However, discharge of Campbell River water from the Duncan Bay project directly into the ocean might confuse Campbell River salmon during the migration and spawning season. In view of the importance of the salmon sport fishery around Campbell River, it is likely that a proposal to build the Duncan Bay project would encounter serious environmental opposition.

(c) Ladore Unit 3

A third generating unit of 25 MW could be installed at the existing Ladore hydro plant, which is located on the Campbell River between the Strathcona and the John Hart projects. This addition would be required if the Duncan Bay project were built in order to balance the hydraulic discharge capacity of the hydro plants on the Campbell River and to gain operational flexibility.

The cost of this unit is estimated to be $7,600,000 at October 1977 prices. This unit would increase average annual energy production of the plant by 17 GWh, but there would be no increase in firm energy. The environmental impact of this unit would be negligible. The construction time for this project would be three years.

(d) Pumped Storage Hydro

A pumped storage hydro project can be regarded as a large electric storage battery, which generates power during peak load periods, and is recharged by pumping during low load periods. In the generation mode, this project operates as a conventional hydro project and water flows from the upper reservoir through the

powerplant to the lower reservoir. In the pumping mode, the generators and reversible pump-turbines of the powerplant are operated as pumps to pump water from the lower reservoir back into the upper reservoir.

The efficiency of the pumping-generating cycle is usually about 70 percent, i.e. for every kilowatt-hour of pumping power used, about 0.7 kilowatt-hour can be recovered in the generating cycle, and the remaining 0.3 kilowatt-hour is lost in pumping and turbine losses, hydraulic losses in the water conduits, generator losses and transformer losses. A pumped storage project usually contains enough water in the upper reservoir to operate the powerplant at full capacity for 10 to 20 hours. The upper reservoir must be refilled periodically through pumping, and the project usually operates on a daily or weekly cycle of full to near empty and then back to full again.

A pumped storage project does not generate any net energy; in fact it actually consumes net energy as a result of pumping-generating cycle losses. The benefit of a pumped storage project is that it provides relatively low cost and dependable generating capacity suitable for short duration peak load operation. It does not have the high fuel costs or long start-up times associated with gas turbines as a peaking alternative. For most power systems, the incremental cost of pumping energy during base load periods is relatively low, and even after recovery of only 70 percent of this energy, a pumped storage project can provide fuel cost savings by reducing high cost fuel requirements from gas turbine projects and thermal peaking plants during peak load periods.

5.1 VANCOUVER ISLAND HYDRO PROJECTS - (Cont'd)

On Vancouver Island, one of the most attractive pumped-storage sites appears to be at Great Central Lake-Doran Lake. This project would use Great Central Lake as a lower reservoir and Doran Lake as an upper reservoir, and would develop a net head (difference in reservoir elevations) of about 572 m. Preliminary cost estimates of this project for various sizes are summarized below:

Project Capacity	Total Cost ($ Millions)	Average Cost ($/kw)
200 MW	106	530
400 MW	150	375
400 with 200 MW Stage I	123	615
200 MW Stage II	34	170
1000 MW	270	270

The above costs include reservoir, tunnel, and powerplant costs, but not transmission costs. The cost of a single circuit 230 kV transmission line for a 400 MW pump storage project from the Great Central Lake-Doran Lake site to Port Alberni, a distance of about 40 km, would be about $5,340,000.

The maximum usable size of a pumped-storage project is typically 10 to 15 percent of the power system peak load, and therefore the maximum size that should be considered for a pumped storage project on Vancouver Island in the future would be about 200 to 400 MW. The earliest feasible in-service date of this pumped storage project would probably be October 1987.

5.2 GAS TURBINES

An oil-fired gas turbine plant would be an economical source of additional peaking capacity on Vancouver Island, but it would be too expensive to operate for base-load power due to its high fuel cost. Since the function of the proposed 500 kV transmission interconnection with the mainland is to provide additional base-load energy as well as capacity, it would not be practical to replace this with a large-scale gas turbine development on the Island.

The capital cost of a 150 MW gas turbine plant with three units of 50 MW each would be about $51,100,000 at October 1977 prices. This is an average $341 per kilowatt. This cost includes all direct costs, contingencies and engineering, but not B.C. Hydro overhead or interest during construction.

The fuel cost for oil is estimated to be 40 mills/kWh at October 1977 prices, based on a plant heat rate of 12,000 Btu/kWh at full load and an oil cost of $0.50/imperial gallon or $3.30/MBtu including storage and handling costs. At 25 percent load, the plant heat rate would rise to about 16,000 Btu/kWh.

The environmental impact of a gas turbine plant is probably less severe than other types of power plants, but there is some concern over the long term reliability and cost of oil fuel supplies, and the wisdom of using such a scarce resource for electric power generation when alternative, more abundant resources are available.

5.3 COMBINED CYCLE PLANTS

A combined cycle plant comprises one or more gas turbine-generator units and a steam-fired thermal unit which uses the exhaust gas from the gas turbines to heat the steam boiler. Combined-cycle plants have high operating costs due to the high cost of oil or gas fuel, although they are more efficient than simple cycle gas turbines.

5.3 COMBINED CYCLE PLANTS - (Cont'd)

The capital cost of a 400 MW combined cycle plant with four gas turbine units of 70 MW each and one steam turbine unit of 120 MW is estimated to be $160,000,000, or about $400 per kilowatt at October 1977 price levels. The fuel cost would be about 28 mills/kWh, based on an overall plant heat rate of 8400 Btu/kWh at full load and an oil cost of $0.50/imperial gallon. At partial loads, the plant would be less efficient and fuel costs would rise.

5.4 COAL-FIRED THERMAL POWERPLANT

A coal-fired powerplant could be built on Vancouver Island which would burn coal that was either mined on the Island at Comox, or mined on the mainland at Hat Creek or the East Kootenays and shipped to a powerplant site on the Island.

(a) Project Description

The Vancouver Island thermal powerplant considered for this study would have four generating units of 150 MW each. The main components of each unit would be a pulverized coal-fired (suspension-fired) boiler, and a steam turbine-generator unit. Each unit could generate a maximum of 1050 GWh/year at 80 percent annual capacity factor, although the average annual capacity factor would probably be closer to 60 percent in practice.

The flue gases from the furnaces would be passed through electrostatic precipitators or bag-house dust collectors where in excess of 99.5 percent of the particulates would be removed. Flue gas desulphurization would not be required for East Kootenay or Hat Creek coals but would probably be necessary for Comox coal.

Cooling would be by closed cycle, wet mechanical-draft cooling towers using salt water. It is possible that fresh water makeup could be secured.

5.4 COAL-FIRED THERMAL POWERPLANT - (Cont'd)

The earliest feasible in-service date of the first generating unit would be October 1986, with the other units following later. The earliest in-service date is based on the acceptance of the "Vancouver Island Thermal Generating Plant Site Selection Inventory" study as a basis for site selection. This would allow detailed environmental studies and engineering feasibility studies to commence by October 1978. If the start of project planning were delayed beyond this date, the earliest feasible in-service date would also be delayed. Total project development would require about 8 years, as shown in the detailed project development schedule in Exhibit 5-1.

The powerplant cost is estimated to be approximately $429,000,000 at October 1977 prices for a four unit 600 MW plant using Hat Creek or East Kootenay coal at a site near Dunsmuir on Vancouver Island. This includes all direct costs, contingencies, and detailed engineering design, but not preliminary engineering, B.C. Hydro overhead, or interest during construction. The average capacity cost would be about $715 per kilowatt at October 1977 prices. The cost of a powerplant using Comox coal would be higher due to added requirements for pollution control equipment (scrubbers) of the high sulphur Comox coal. A 600 MW Comox powerplant would cost about $495,000,000 total, or $824 per kilowatt.

The Dunsmuir project site is located a half mile from the Dunsmuir substation, so transmission costs for this project would be negligible. A project site at the Comox coal deposit could be located near Courtenay, and would require 40 km of double-circuit 230 kV transmission from Courtenay to Dunsmuir substation, at a cost of about $12,500,000.

VANCOUVER ISLAND
4 X 150 MW COAL-FIRED THERMAL POWERPLANT
PROJECT DEVELOPMENT SCHEDULE

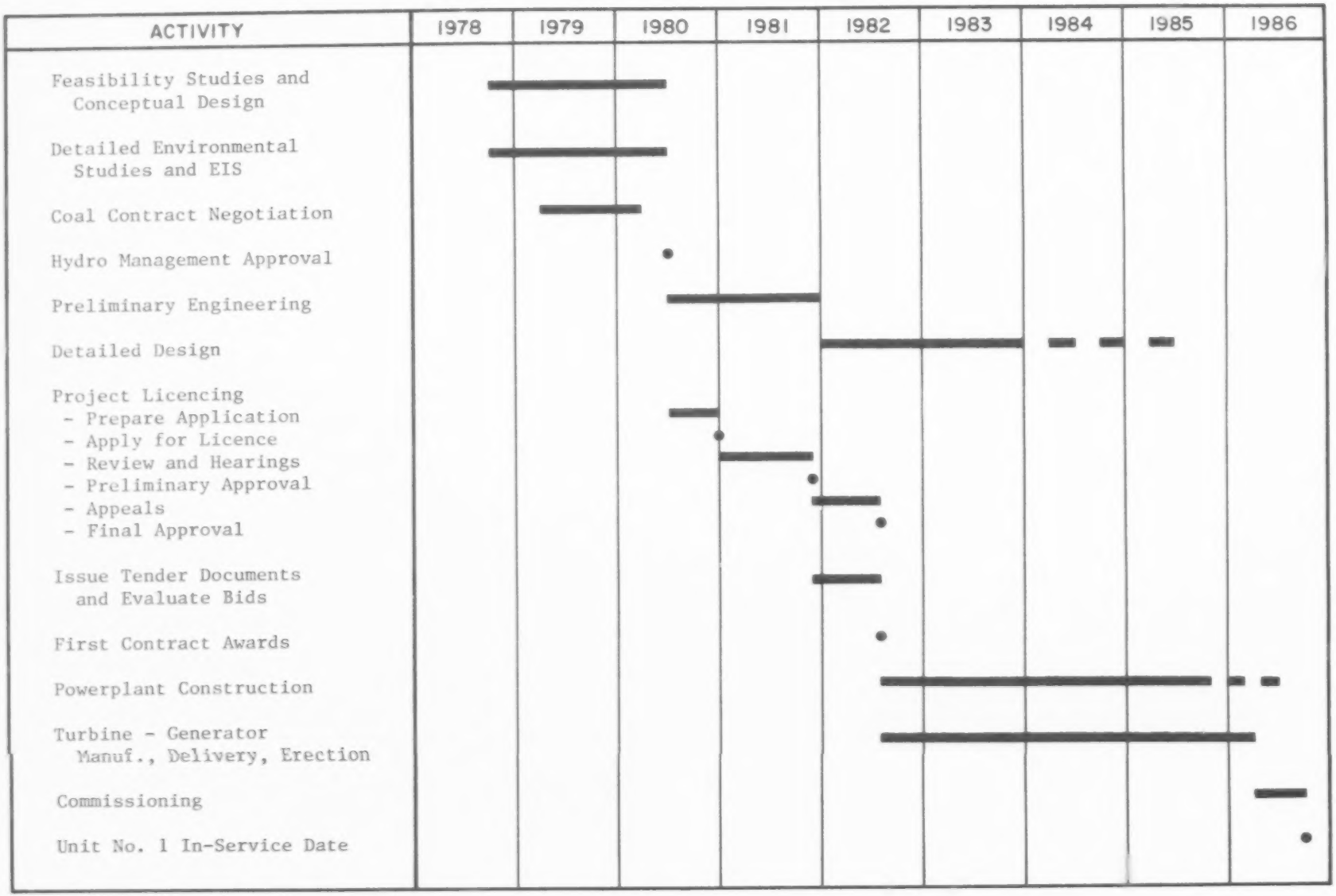


EXHIBIT 5-1

5.4 COAL-FIRED THERMAL POWERPLANT - (Cont'd)

The powerplant net heat rate would be about 10,500 Btu/kWh with Hat Creek coal, 10,000 Btu/kWh with Comox coal, and about 9800 Btu/kWh with East Kootenay coal.

(b) Alternative Coal Sources and Costs

There are three possible coal sources to supply the Vancouver Island thermal plant. B.C. Hydro holds the licences for the Hat Creek deposit, and sufficient exploration and testing has been completed to confirm it as a viable source of thermal coal. The East Kootenay region has several active coal mines and large reserves of coal. The Comox coalfield is a known coal resource on Vancouver Island.

(i) Hat Creek Coal

The cost of Hat Creek coal at the mine site is estimated to be $6.20 per short ton, and the cost of transporting this coal from Hat Creek to Dunsmuir on Vancouver Island is estimated to be a further $12.80 per ton, based on transport of three to four million tons of coal annually from the mine to Glenfraser by conveyor belt, from Glenfraser to Squamish (Britannia) by B.C. Rail, and from Squamish to Dunsmuir by barge. The cost of Hat Creek coal on Vancouver Island would thus be about $19.00 per ton. The details of this transportation cost estimate are summarized in Table 5-1. The heat content of this coal is about 5500 Btu/lb and the net heat rate of the powerplant would be about 10,500 Btu/kWh. The resulting fuel cost with Hat Creek coal would be about $1.73/MBtu, or 18.1 mills/kWh.

TABLE 5-1

HAT CREEK
COAL TRANSPORTATION COSTS

Hat Creek Coal for 600 MW Station

Coal Volume Transported:

4.0 million tons/year maximum
3.0 million tons/year average

Method of Transport:

Conveyor from Hat Creek mine to Glenfraser
B.C. Rail from Glenfraser to Britannia
Barge from Britannia to Dunsmuir

Estimated Cost:

	$/ton
Mine storage/reclaim at Hat Creek	0.30
Conveyor to Glenfraser (20 km)	3.00
Storage/reclaim/rail car loading at Glenfraser	0.50
Railway Tariff to Britannia (225 km)	4.50
Total to Britannia	8.30
Unload and transfer to barge	2.25
Tug and barge to Dunsmuir (100 km)	0.75
Unload barge and transfer to conveyor	1.00
Conveyor to powerplant (3 km)	0.50
Total Transportation Cost	12.80

5.4 COAL-FIRED THERMAL POWERPLANT - (Cont'd)

If a thermal plant using Hat Creek coal were built on the Island, the capacity of the proposed Hat Creek powerplant could be reduced by a corresponding amount. Thus, the coal reserves at Hat Creek would still be adequate to support the same total level of thermal generating capacity.

(ii) Comox Coal

The coal resources on Vancouver Island are described in detail in the report on "Coal Resources of British Columbia", prepared for B.C. Hydro by Dolmage Campbell and Associates in 1975. The total coal reserves on Vancouver Island were estimated in this study at about 650 million tons. However, most of these coal reserves would require underground mining, which is relatively costly, and which would require labour skills that are currently in short supply in Canada.

The most suitable coal deposit on Vancouver Island to support a coal-fired power plant is located at the Comox coalfield. The Suquash coalfield on Vancouver Island near Port Hardy was also explored recently by B.C. Hydro, but those coal reserves were found to be too poor in quality and too costly to mine in order to support a thermal powerplant. The Nanaimo coal fields, which have had a long coal mining history, are almost exhausted and contain practically no remaining economically minable coal reserves.

The Comox coalfield, comprising the Cumberland and Tsable deposits, is located on eastern Vancouver Island and is centered near the town of Cumberland. Proven and probable reserves accessable by underground

mining were estimated by Dolmage-Campbell at 64 million tons of 9,600 Btu/lb coal, although this estimate is considered conservative by the owner of this coal property. The possible reserves were estimated to be an additional 440 million tons of coal.

A 600 MW Comox powerplant would require a maximum of 2.2 million tons of such coal per year and an average of about 1.6 million tons per year for a 35-year lifetime. Comox coal has a high (1.4 percent) sulphur content, and a powerplant using Comox coal would probably require scrubbers for pollution control and would operate at a less efficient heat rate.

The Comox coal property is owned by Weldwood of Canada Limited, which is studying the feasibility of opening a coal mine there in association with Luscar Coal Co. Recent discussions with Weldwood indicate that coal reserves are still being explored. However, the price of this coal would be based on the international tidewater price of thermal coal, which is currently about $30-35/ton for coal with a calorific value of about 12,000 Btu per pound. Since Comox coal could be exported to international markets, B.C. Hydro would have to pay this international export price. A cost of $30/ton for 12,000 Btu/lb coal would result in a fuel cost of about $1.25/MBtu, or 12.5 mills/kWh at a plant net heat rate of 10,000 Btu/kWh.

(iii) East Kootenay Coal

The East Kootenay coalfields are the largest in British Columbia, and the only significant coal

producing area in the Province at present. Much of this coal is high quality coking coal which is mined for export, and which would be too valuable to use as a thermal fuel. Most of the East Kootenay coalfields are privately owned, except for the Cadorna Creek area (Crown land held in reserve for B.C. Hydro) and the Dominion Coal Blocks. The total thermal (i.e. non-coking) coal resources in the East Kootenays accessible by open pit mining are estimated to be 190 million tons of 11,000 Btu/lb coal (see "Coal Resources of British Columbia" by Dolmage Campbell & Associates, May 1975). This would be more than adequate to support a 600 MW thermal plant, which would require about 1.3 million tons of such coal annually at 60 percent average annual capacity factor.

One possible source of coal supply for a limited thermal power development would be the coarse refuse coal from washing plant by-products of the existing coking coal mining operations. This refuse coal does not meet the high standards required for coking coal, but it would still be acceptable as a thermal fuel. The production of coarse refuse coal in the East Kootenay area is currently about 1,000,000 tons annually from the Kaiser coal mine near Sparwood, plus smaller quantities from Coleman Collieries and from the Fording mine near Elkford. The average heat content of this coarse refuse coal is about 7,200 Btu/lb. A 1,000,000 ton annual supply of this refuse coal would support about 275 MW of thermal generating capacity at 60 percent average annual capacity factor.

5.4 COAL-FIRED THERMAL POWERPLANT - (Cont'd)

In addition to these refuse coal supplies, thermal coal is also available in the East Kootenays, either as a mine by-product or as separately mined thermal coal. Recent discussions with East Kootenay coal producers indicate that the cost of thermal coal at the mine-site would be about $18-20/ton, and the cost of refuse coal would probably be about $5/ton.

The cost of purchasing East Kootenay coal and shipping it to a powerplant site at Dunsmuir on Vancouver Island is shown in Table 5-2. These costs indicate that the fuel cost of thermal coal from the East Kootenays delivered to Vancouver Island would be about 14.3 mills/kWh.

In view of the uncertainty about exact coal costs, all three coal resources described above were considered as alternatives in this study.

(c) Site Selection Study

In April 1974, B.C. Hydro commissioned Beak Consultants Limited, Montreal Engineering Company Limited, and Commonwealth Associates, Inc. to conduct a multi-disciplinary search for suitable powerplant sites throughout Vancouver Island. This study, which included coal-fired thermal plants, is summarized in the report on "Vancouver Island Thermal Generating Plant Site Selection Inventory", July 1975. For coal-fired plants the initial selection identified 168 sites which appeared to satisfy siting parameters. After the first screening step, during which the sites were evaluated with respect to overriding environmental and engineering parameters, the total number of sites was reduced to 51. Further

TABLE 5-2

EAST KOOTENAY COAL COSTS

($/ton)

Item	Thermal Coal	Refuse Coal
Purchase cost at East Kootenay (includes sorting and loading)	18.00	5.00
Railway Freight (East Kootenay-Roberts Bank)	12.50	12.50
Unloading and transfer to barge	2.25	2.25
Tug and barge to Vancouver Island	.75	.75
Unloading barge and transfer by conveyor to powerplant site	1.50	1.50
Total coal cost	35.00	22.00
Heat content, Btu/lb	12,000	7,200
Fuel cost, $/MBtu	1.46	1.53
Heat rate, Btu/kWh	9,800	10,000
Fuel cost, mills/kWh	14.3	15.3

screening using more detailed environmental and engineering parameters resulted in the selection of nine sites which were studied in detail.

The best overall site for burning imported East Kootenay or Hat Creek coal was Dunsmuir. It ranked second economically and third environmentally. The best economic site (roughly $17/kW cheaper) was one of the worst from an environmental viewpoint. The two sites that were better than Dunsmuir environmentally suffer a stiff economic penalty of over $60/kW.

The Dunsmuir site is located approximately 3 km south of Bowser and 1 km inland from Qualicum Bay. It is within 1 km of the existing Dunsmuir Substation. Road and rail access is also close. A new coal unloading dock would be built at the coast near Bowser and the coal transported to the site by conveyor.

A powerplant burning Comox coal would probably be located at a site near Courtenay.

(d) Environmental Impact

General indications from the Site Selection Inventory are that there would be no serious environmental problems with air emissions or noise for a powerplant site near Dunsmuir. A powerplant at Courtenay burning high sulphur Comox coal would probably require scrubbers for sulphur dioxide control however.

Fresh water can be secured at Dunsmuir for boiler makeup (2 cfs) but the possibility of fresh water for cooling tower makeup (20 cfs) could have an impact on the important fisheries on the Big Qualicum River. Saltwater cooling may therefore be required.

5.4 COAL-FIRED THERMAL POWERPLANT - (Cont'd)

The Vancouver Island area is a recreation area and visual impact of the plant could be high. Both the cooling towers and the smokestack would be visible from a distance. Drift and fogging from the cooling towers could also be a problem.

The environmental impact of the coal mining and transport facilities required to support a 600 MW thermal powerplant must also be considered. Such a plant would burn 1 to 2 million tons of coal per year. If this coal were mined on the Island at Comox, this scale of coal mining could have a significant impact. If this coal were mined on the mainland in the East Kootenays and transported to the Island, an additional burden would be placed on the heavily loaded railway lines from this area to Vancouver, and a major coal transportation operation would be required, including coal barges, a coal unloading dock at Bowser, a coal conveyor belt to Dunsmuir, and coal stockpiles at intermediate points. Each phase of this operation would involve some adverse visual impact, high noise levels, and problems with coal dust control.

5.5 NUCLEAR POWER

The feasibility and public acceptability of a nuclear project on Vancouver Island have not yet been determined. In any case, a nuclear project on the Island could not be built before 1991 due to the long lead time of 11 to 13 years required for project planning, site selection, licencing and construction. Therefore nuclear power would not be a feasible alternative to serve load growth before that date. However, if current studies indicate that nuclear power would be economical and also required after that date, planning for a nuclear project on the Island should commence soon.

5.5 NUCLEAR POWER - (Cont'd)

A nuclear project would probably be one of the CANDU family of reactors which are fuelled with natural uranium and moderated with heavy water. All this equipment and fuel can be produced in Canada. The minimum standard unit size would be 630 MW for a plant with once-through sea water cooling. Each unit would generate about 4300 GWh/year at 78 percent average annual capacity factor.

A specific site for a nuclear project on Vancouver Island has not been identified. A nuclear project would probably be located near the sea coast for access to cooling water, but it must also be located in a seismically safe area.

The direct cost of a two-unit 1,260 MW nuclear plant is estimated to be about $1,037,000,000, or $823 per kilowatt at 1977 prices. The unit fueling cost for a CANDU reactor is estimated to be about 2.9 mills/kWh, based on a fuel cost of $0.25/MBtu and a heat rate of 11,650 Btu/kWh.

In view of the widespread public concern about nuclear projects, a long lead time would be required to determine the public acceptability of such a project and to complete specific project site selection and licencing. A nuclear project could have some adverse environmental impact, but any alternative, such as the development of remaining marginal hydro resources or further reliance on limited fossil fuel resources, would also have an adverse environmental impact. It will no longer be possible in the future to find power sources that have a low cost and negligible environmental impact and are not dependent on limited natural resources. Under such circumstances all the alternatives, including nuclear, must be given serious consideration.

5.6 COST COMPARISON OF PROJECTS

The costs of the alternative sources of power supply described in this chapter are summarized in Table 5-3 and Exhibit 5-2. Table 5-3 shows the average capital costs of generating capacity and transmission capacity and the average fuel costs of each project. Exhibit 5-2 shows the uniform average annual costs of power as a function of project capacity factor.

The cost of supplying power from the mainland with the 500 kV transmission is computed by assuming that average future mainland power generation costs will be equal to the average cost of the Hat Creek project. Thus the incremental cost of mainland power supply to Vancouver Island will be composed of the average transmission cost to the Island, plus the average cost of Hat Creek power with some small adjustments for transmission losses. This assumption about future mainland power costs is conservative in the sense that the cost of developing additional mainland hydro power appears to be lower than the cost of thermal power at Hat Creek.

The two 500 kV transmission circuits from Cheekye to Dunsmuir are estimated to cost $315,000,000 at 1977 prices. The full capacity of these circuits is 1100 MW each for a total capacity of 2200 MW. This new transmission will also serve the Sunshine coast area on the Sechelt peninsula. If this 500 kV transmission is not built, a separate 230 kV circuit from Cheekye to Sechelt would be required in 1983 to serve this area, at cost of about $18,000,000. Thus, the net cost of the new submarine transmission to Vancouver Island can be considered to be about $297,000,000, or about $135/kilowatt of transmission capacity, not including inflation and interest during construction.

The direct cost of the Hat Creek coal-fired thermal generating plant is estimated to be $612 per kilowatt at October 1977 prices for the powerplant with 2000 MW of net generating capacity and about $46 per

TABLE 5-3

COSTS OF ALTERNATIVE POWER SOURCES

FOR VANCOUVER ISLAND

(1977 price levels)

Power Source	Capacity Cost $/kW	Transm. Cost $/kW	Fuel Cost mills/kWh	Variable O.M Cost mills/kWh
Transmit Mainland Power from Hat Creek	632	187	6.0	0.5
Gas Turbines	341		40.0	2.4
Combined Cycle	400		28.0	2.4
Nuclear	823	15 **	2.9	0.6
Coal Thermal Plant on Vancouver Island:				
Kootenay coal	715	0	14.3	0.5
Hat Creek coal	715	0	18.1	0.5
Comox coal	824	21	12.5	0.5
Duncan Bay Hydro *	593	0		
Kokish Hydro *	501	35		
Ladore Unit 3 Hydro *	304	0		
Pumped Storage	375	13	9.3 **	

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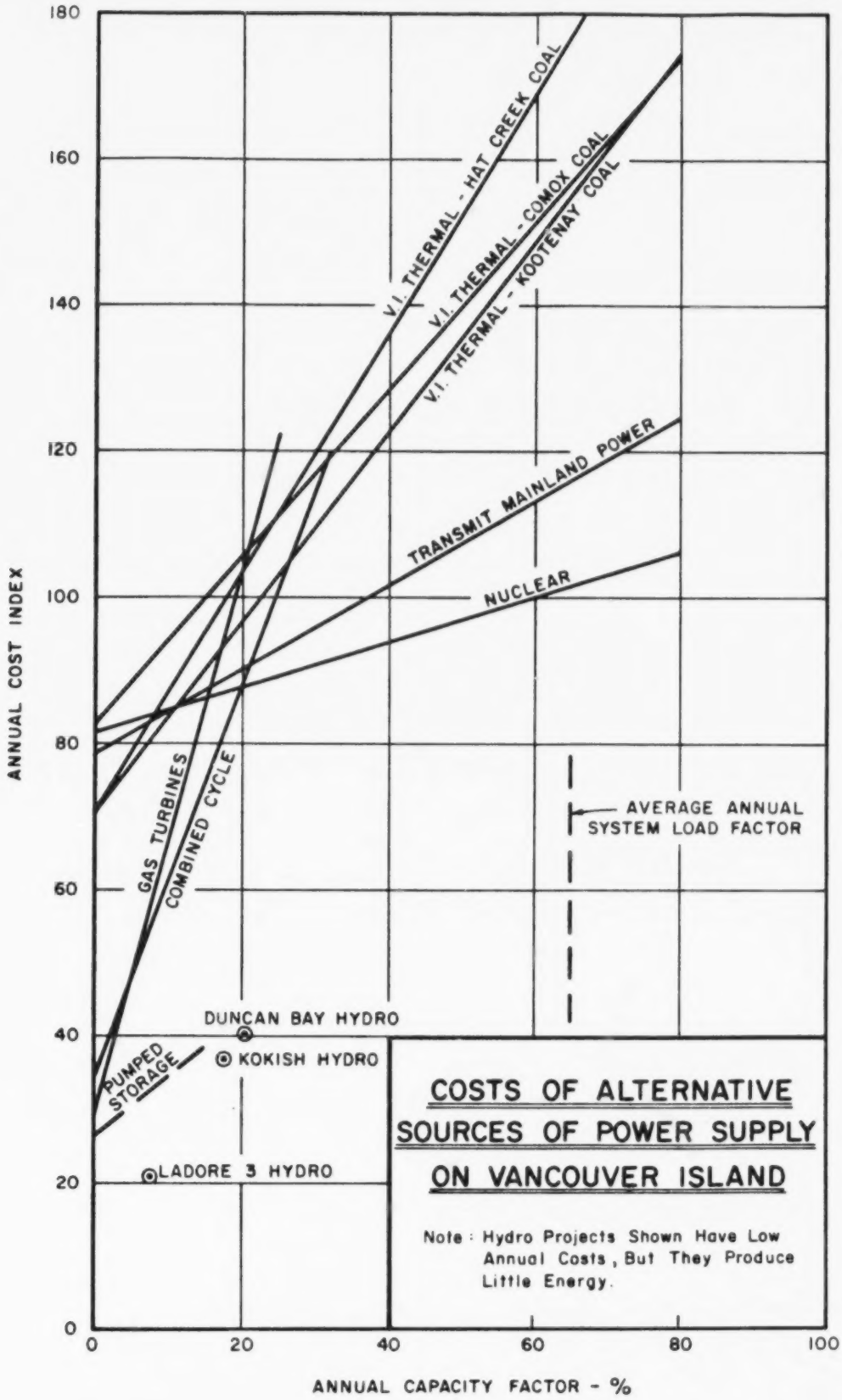
* Hydro projects shown have lower capacity costs than the transmission alternative, but they provide little energy.

** Preliminary estimate.


180
160
140
120
100
80
60
40
20
0
ANNUAL COST INDEX
V.I. THERMAL - HAT CREEK COAL
V.I. THERMAL - COMOX COAL
V.I. THERMAL - KOOTENAY COAL
TRANSMIT MAINLAND POWER
NUCLEAR
GAS TURBINES
COMBINED CYCLE
AVERAGE ANNUAL SYSTEM LOAD FACTOR
DUNCAN BAY HYDRO
KOKISH HYDRO
PUMPED STORAGE
LADORE 3 HYDRO
COSTS OF ALTERNATIVE SOURCES OF POWER SUPPLY ON VANCOUVER ISLAND
Note : Hydro Projects Shown Have Low Annual Costs, But They Produce Little Energy.
0
20
40
60
80
100
ANNUAL CAPACITY FACTOR - %

kilowatt for associated transmission. The peak load transmission losses from Hat Creek to Vancouver Island are estimated to be about 3.3 percent. The net direct cost of Hat Creek power by the time it reaches Vancouver Island will then be about $632 per kilowatt of generating capacity, and $187 per kilowatt of transmission capacity at 1977 prices, not including interest during construction.

The average cost of Hat Creek fuel is estimated to be about 5.9 mills/kWh, based on a coal mining cost of $6.20/ton, a coal heat content of 5500 Btu/lb and a plant net heat rate of 10,500 Btu/kWh. The addition of about 2.0 percent average transmission losses from Hat Creek to Vancouver Island would raise the net fuel cost to 6.0 mills/kWh. These costs for mainland power supply to Vancouver Island are also summarized in Table 5-3.

The alternative power costs shown in Table 5-3 are plotted over a range of plant capacity factors in Exhibit 5-2. This exhibit shows that the most economic base load power supply in the future will be nuclear power. However, the lead time for building a nuclear project is so long that it could not be completed in time to be a feasible alternative in the 1980s. The transmission of mainland power would be the next most economic source for base-load power. The alternative of building a thermal plant on Vancouver Island which uses Hat Creek or East Kootenay coal would have a lower capital cost than transmission of mainland power, but would have a much higher operating cost due to the high fuel cost on the Island. This alternative would not be economic at the system load factor of 65 percent compared to either nuclear power or transmission of mainland power. A Vancouver Island thermal plant using Comox coal also would be uneconomic due to its high fuel cost and higher capital cost. A gas turbine plant could provide economic peaking capacity only at annual capacity factors of less than 15 percent. A combined cycle plant may be economic at annual plant

5.6 COST COMPARISON OF PROJECTS - (Cont'd)

capacity factors less than 20 percent. Pumped-storage and the potential hydro projects at Kokish, Duncan Bay, and Ladore would all be economic sources of peaking capacity, but they could not serve base loads.

The most economic sources of power supply described above are combined into alternative generation expansion programs in the next chapter, and these alternative generation expansion programs are then compared on a discounted cash flow basis to determine the most economic program of power supply.

SECTION 6.0 - ECONOMIC COMPARISON OF ALTERNATIVE PLANS

6.1 POWER SYSTEM PLANNING

The alternative sources of power supply described in this study must be compared against each other on an economic basis over an extended period of time. A particular power project cannot be examined in isolation, since its operation, and its fuel costs in the case of a thermal project, will depend on the composition and operation of the rest of the power system. An entire sequence of projects must therefore be examined as an integrated plan to supply generation expansion over an extended period of time; and alternative generation expansion plans which include different projects can be compared against each other in order to determine the most economical plan, and the most economical projects included in that plan. In order to determine the economic feasibility of the proposed new 500 kV Cheekye-Dunsmuir transmission to Vancouver Island, a generation expansion plan including this project must be compared to alternative generation expansion plans which do not include this transmission project, but which include either alternative transmission projects or a combination of alternative power projects on Vancouver Island.

This economic comparison of alternative generation expansion plans encompasses power planning for the entire B.C. Hydro integrated system, including both Vancouver Island and mainland British Columbia. The sequence of new generation projects required to meet the load growth from 1982 to 1998 has been studied. The total discounted cost of a generation expansion sequence is determined, including the capital costs of all new projects, and the variable annual costs for fuel, operation, and maintenance; and alternative sequences are then compared on the basis of these costs. Inflation of capital costs, fuel costs, and operation and maintenance costs is included, at a rate of

6.1 POWER SYSTEM PLANNING - (Cont'd)

5.75 percent annually after 1982, and at a slightly higher rate before that date. The annual power load and fuel requirements are assumed to remain constant after 1998, and an allowance for plant replacement (i.e. amortization of capital costs) after that date is also included. The total costs of alternative generation expansion plans are discounted to 1977 at various discount rates from 9 to 15 percent annually.

6.2 RESERVE POWER REQUIREMENTS

In composing a sequence of future generation expansion, it is essential to ensure that both the average electrical energy demands and the peak load demands can be supplied in every year. There must also be an adequate margin of reserve generating capacity and reserve firm energy to allow for possible forced outages of some of the generating units and submarine transmission circuits which supply this power. This reserve also allows for scheduled maintenance outages, and provides a contingency allowance for possible unanticipated load growth and construction delays of new generation projects.

The reserve generating capacity requirements are determined with a sophisticated computer program that considers the pattern of daily power loads over a period of a year, the scheduled maintenance outages and the average forced outage rate of each generating unit, and the forced outage rates of the submarine transmission power supplies. This program then determines the annual probability of loss-of-load, or load shedding, due to a power demand in excess of total available power supply.

The standard allowable level of risk is established as 0.1 day/year or less of expected loss-of-load. If a proposed plan has a higher risk index than this, it is considered not firm. The maximum peak annual load that can be served within this allowable risk index is

6.2 RESERVE POWER REQUIREMENTS - (Cont'd)

defined as the total dependable capacity of the power system. The total reserve capacity is the difference between total dependable capacity and total installed capacity. This procedure for determining dependable capacity is standard practice for B.C. Hydro and most other power utilities in North America.

As a general rule for the Vancouver Island power system, where outage contingencies are large and forced outage rates of submarine transmission circuits are relatively low, the required reserve capacity is approximately, but not exactly, equal to either the capacity of the largest submarine transmission circuit, or the two largest thermal generating units, or 15 percent of the peak annual load, whichever is largest. This rule may assist the reader in understanding why the reserve requirements in some of the plans discussed in this section appear so large.

The reserve margin of firm energy required is equal to the firm energy capability of the largest single thermal unit, or one half year's growth of total energy demand, whichever is larger. This reserve would allow the largest thermal unit to suffer a forced outage for a 3 month period in the winter without resulting in loss-of-load. If two or more units were forced out simultaneously however, there could be a loss of energy.

6.3 ALTERNATIVE GENERATION EXPANSION PLANS

The alternative generation expansion plans considered in this study are described briefly below.

A. 500 kV Cheekye-Dunsmuir Transmission

This is the base plan, which includes the 500 kV ac transmission project from Cheekye to Dunsmuir on Vancouver Island

in 1983, and which will use mainland power to supply load growth on Vancouver Island after 1983. The 2000 MW Hat Creek thermal power development starting in 1986 will be a major component of this plan.

The load resources balance of this base plan for Vancouver Island is summarized in Table 6-1. New projects scheduled after the Cheekye-Dunsmuir transmission in this plan are only suggestions.

B. 230 kV Cheekye-Dunsmuir Transmission

Nuclear 1995

The 500 kV Cheekye-Dunsmuir Transmission project would supply much more transmission capacity than is required in the immediate short term. As an alternative, a smaller capacity 230 kV ac Cheekye-Dunsmuir Transmission project could be built, with a capacity of 500 MW per circuit instead of 1100 MW. This project is described previously in Section 4.5.

The load resources balance of this 230 kV transmission plan is summarized in Table 6-2. The in-service dates of circuits 1 and 2 would still be October 1983 and October 1986 respectively. A new source of power supply on Vancouver Island would be required by 1991. Since the 230 kV transmission lines could supply adequate base load energy to Vancouver Island at this time, it would be primarily peak load generating capacity that would be required for several years after 1991, and this could be supplied most economically with the 150 MW Duncan Bay and the 25 MW Ladore hydro projects in 1991, and a 400 MW pumped - storage hydro project in 1992 and 1993. By 1995 an additional base load power project should be scheduled. The most economical base load power supply

TABLE 6-1

VANCOUVER ISLAND LOAD RESOURCES BALANCE A

500 kV TRANSMISSION PLAN

Year Apr-Mar	Additional Projects	Total Capacity MW	Dependable Capacity MW	Peak Load MW	Firm Energy GWh	Required Energy GWh
1982/83	Existing System	1690	1460	1450	9,520	8,610
1983/84	500 kV Circuit 1	2790	1780	1535	17,200	9,050
1984/85	-	2790	1780	1625	17,200	9,520
1985/86	-	2790	1780	1720	17,200	10,000
1986/87	500 kV Circuit 2	3890	2900	1820	24,900	10,525
1987/88	-	3890	2900	1925	24,900	11,050
1988/89	-	3890	2900	2030	24,900	11,600
1989/90	-	3890	2900	2140	24,900	12,120
1990/91	-	3890	2900	2260	24,900	12,790
1991/92	-	3890	2900	2390	24,900	13,430
1992/93	-	3890	2900	2520	24,900	14,100
1993/94	Retire Georgia GT	3825	2840	2650	24,780	14,780
1994/95		3825	2840	2790	24,780	15,490
1995/96	150 MW Duncan Bay	3975	2985	2930	24,960	16,230
	25 MW Ladore 3	4000	3010		24,960	
1996/97	400 MW Pump Storage	4400	3390	3090	24,960	17,010
	Retire 138 kV Cables	4150	3140		23,080	
1997/98	New Project			3250		17,820

TABLE 6-2

VANCOUVER ISLAND LOAD RESOURCES BALANCE B

230 kV TRANSMISSION PLAN AND NUCLEAR 1995

Year Apr-Mar	Additional Projects	Total Capacity MW	Dependable Capacity MW	Peak Load MW	Firm Energy GWh	Required Energy GWh
1982/83	Existing System	1690	1460	1450	9,520	8,610
1983/84	230 kV Circuit 1	2190	1775	1535	13,000	9,050
1984/85	-	2190	1775	1625	13,000	9,520
1985/86	-	2190	1775	1720	13,000	10,000
1986/87	230 kV Circuit 2	2690	2260	1820	16,500	10,525
1987/88	-	2690	2260	1925	16,500	11,050
1988/89	-	2690	2260	2030	16,500	11,600
1989/90	-	2690	2260	2140	16,500	12,180
1990/91	-	2690	2260	2260	16,500	12,790
1991/92	150 MW Duncan Bay	2840	2405	2390	16,680	13,430
	25 MW Ladore 3	2865	2430		16,680	
1992/93	200 MW Pump Storage	3065	2625	2520	16,680	14,100
1993/94	200 MW Pump Storage	3265	2820	2650	16,680	14,780
	Retire Georgia GT	3200	2760		16,570	
1994/95		3200	2760	2790	16,570	15,490
1995/96	630 MW Nuclear	3830	2980	2930	16,870	16,230
1996/97	630 MW Nuclear	4460	3200	3090	21,170	17,010
	Retire 138 kV Cables	4210	2950		19,300	
	New Project					

would be nuclear power, and the generation expansion with nuclear starting in 1995 is summarized in Table 6-2.

C. 230 kV Cheekye-Dunsmuir Transmission
600 MW Coal 1994-96
Nuclear 1997

This plan would be identical to Plan B up to 1994. If an early nuclear program would not be feasible or publically acceptable for some reason, then coal-fired thermal power would be required on Vancouver Island in 1994. A 600 MW coal-fired thermal power development could serve load growth from 1994 to 1996, and nuclear power could start in 1997, as shown in Table 6-3. The cost of such a delay in a nuclear development is very high however, as will be shown in the following section.

D. Vancouver Island Generation Plan
600 MW EK Coal 1986-1989
Nuclear 1991

The most economic alternative plan utilizing only generation on Vancouver Island would include a combination of several power sources. Exhibit 5-2 shows that nuclear power would be the most economic for serving base loads in the future, but nuclear power would not be available until 1991. Nuclear power development should be planned for Vancouver Island at the earliest feasible date in any alternative power supply plan which does not include additional transmission to the mainland. Before this nuclear in-service date, a coal-fired thermal powerplant on Vancouver Island using East Kootenay coal would provide the most economic base-load generating capacity. A pumped storage project and the hydro sites at Kokish, Duncan Bay and Ladore Unit 3 would provide the most economic peaking capacity and should also be scheduled in any alternative if they are environmentally acceptable.

TABLE 6-3

VANCOUVER ISLAND LOAD RESOURCES BALANCE C

230 kV TRANSMISSION PLAN AND COAL 1994

Year Apr-Mar	Additional Projects	Total Capacity MW	Dependable Capacity MW	Peak Load MW	Firm Energy GWh	Required Energy GWh
1982/83	Existing System	1690	1460	1450	9,520	8,610
1983/84	230 kV Circuit 1	2190	1775	1535	13,000	9,050
1984/85	-	2190	1775	1625	13,000	9,520
1985/86	-	2190	1775	1720	13,000	10,000
1986/87	230 kV Circuit 2	2690	2260	1820	16,500	10,525
1987/88	-	2690	2260	1925	16,500	11,050
1988/89	-	2690	2260	2030	16,500	11,600
1989/90	-	2690	2260	2140	16,500	12,180
1990/91	-	2690	2260	2260	16,500	12,790
1991/92	150 MW Duncan Bay	2840	2405	2390	16,680	13,430
	25 MW Ladore 3	2865	2430		16,680	
1992/93	200 MW Pump Storage	3065	2625	2520	16,680	14,100
1993/94	200 MW Pump Storage	3265	2820	2650	16,680	14,780
	Retire Georgia GT	3200	2760		16,570	
1994/95	150 MW Coal Thermal	3350	2880	2790	16.870	15,490
1995/96	150 MW Coal Thermal	3500	3010	2930	17.920	16,230
1996/97	2 x 150 MW Thermal	3800	3250	3090	20,020	17,010
	Retire 138 kV Cables	3550	3000		18,140	
1997/98	630 MW Nuclear	4180	3240	3250	19,190	17,820
1998/99	New Project					

6.3 ALTERNATIVE GENERATION EXPANSION PLANS - (Cont'd)

The earliest feasible in-service date for a coal-fired thermal power plant on Vancouver Island would be October 1986. To serve the load growth between October 1983 and October 1986, a 150 MW gas turbine project could be scheduled for October 1983, the 150 MW Duncan Bay hydro project could be scheduled for October 1984, and the 25 MW Ladore Unit 3 could be scheduled for October 1985, as shown in Table 6-4.

This sequence would just barely provide the required dependable capacity from 1983 to 1986, and it would involve a significant risk of deficits in firm energy in 1985/86 and 1986/87. There would also be a heavy demand on gas turbine generation from 1983 to 1986, with at least 200 gWh of gas turbine generation required in the winter of 1985/86, and the same amount the following winter. Each 200 gWh of gas turbine generation would require about 16 million gallons of fuel oil, which may be in very short supply by 1985. If the first thermal generating unit scheduled for October 1986 were delayed in its construction and commissioning schedule, or if it were shut down due to a forced outage after commissioning, there would be serious power deficits combined with even higher fuel oil demands for gas turbine generation during the winter of 1986/87. With the prospect of possible power rationing and deficits for such a plan, it might be necessary to take stringent measures to enforce electricity conservation and curtail industrial load growth on Vancouver Island until the new coal-fired thermal plant was operational.

The first 150 MW unit of the four unit, 600 MW coal-fired powerplant would have an earliest in-service date of October 1986. The most economic thermal project, which is used in this plan, would burn East Kootenay coal transported to a powerplant site near Dunsmuir on Vancouver Island. Units 2, 3 and 4 would be scheduled later at 1-year intervals, as shown in Table 6-4.

TABLE 6-4

VANCOUVER ISLAND LOAD RESOURCES BALANCE D

600 MW COAL 1986-1989, NUCLEAR 1991

Year Apr-Mar	Additional Projects	Total Capacity MW	Dependable Capacity MW	Peak Load MW	Firm Energy GWh	Required Energy GWh
1982/83	Existing System	1690	1460	1450	9,520	8,610
1983/84	150 MW Gas Turbines	1840	1580	1535	9,785	9,050
1984/85	150 MW Duncan Bay	1990	1720	1625	9,970	9,520
1985/86	25 MW Ladore 3	2015	1760	1720	9,970	10,000
1986/87	150 MW Coal Thermal	2165	1850	1820	10,240	10,525
1987/88	150 MW Coal Thermal	2315	1950	1925	11,290	11,050
1988/89	150 MW Coal Thermal	2465	2055	2030	12,340	11,600
1989/90	150 MW Coal Thermal	2615	2170	2140	13,390	12,180
1990/91	160 MW Kokish Hydro	2775	2340	2260	13,620	12,790
1991/92	630 MW Nuclear 1	3405	2480	2390	14,670	13,430
1992/93	200 MW Pump Storage	3605	2670	2520	14,670	14,100
1993/94	Retire Georgia GT	3540	2645	2650	14,560	14,780
1994/95	630 MW Nuclear 2	4170	2810	2790	18,860	15,490
1995/96	200 MW Pump Storage	4370	3000	2930	18,860	16,230
1996/97	Retire 138 kV Cables	4115	2800	3090	17,000	17,010
	New Project					

The firm energy balance for 1986/87 shows that an energy deficit could occur at this time due to an outage of the first thermal unit, but if this unit were commissioned on time and suffered no forced outages, such a deficit would not occur.

The 160 MW Kokish hydro project would be scheduled for October 1990 in this plan.

The first 630 MW nuclear unit would be scheduled for October 1991, followed by the first 200 MW pumped storage unit in 1992. The second nuclear unit would be required by 1994, as shown in Table 6-4. Although the contribution of these large nuclear units to the dependable capacity and firm energy of the Vancouver Island power system is limited, they would nevertheless provide a much higher contribution of dependable power to the integrated provincial power system.

The initial in-service date of the Hat Creek Project would not be delayed in this plan, although subsequent mainland generation projects would be delayed slightly to balance the total provincial power loads and resources.

E. Vancouver Island Generation Plan
600 MW Comox Coal 1986-1989
Nuclear 1991

This plan is similar to Plan D described above, except that a 600 MW Comox coal-fired powerplant would be developed near Courtenay, instead of a 600 MW thermal powerplant at Dunsmuir using East Kootenay coal. A Comox powerplant would be more costly however.

6.3 ALTERNATIVE GENERATION EXPANSION PLANS - (Cont'd)

F. Vancouver Island Generation Plan
1200 MW Coal 1986-1995
Nuclear 1996

This plan shows the effect of a delay in the development of nuclear power in the Vancouver Island alternative generation plan. If an early nuclear power development with the first unit in-service in 1991 were not feasible, either because no feasible nuclear sites were available on Vancouver Island, or because of delays in project planning and licencing due to public controversy, then additional coal-fired thermal generation would be required on Vancouver Island after 1991. This Plan F is similar to Plan D until 1990, and then a 600 MW Comox coal-fired powerplant would be scheduled from 1991 to 1995. The first 630 MW nuclear unit would be delayed 5 years until 1996, as shown in Table 6-5.

G. Mixed Power Supply Plans

The possibility of a mixed transmission plus Vancouver Island generation plan has also been suggested. Exhibit 5-2 shows that the Kokish and Duncan Bay hydro projects and pumped storage hydro would be quite economic. However, these hydro projects would provide mostly generating capacity with little energy, and the Vancouver Island system will require a base-load source of electric energy as well as generating capacity. After 1983, if the new Cheekye-Dunsmuir transmission line is built, it would be more economic to add additional generating capacity to the integrated power system at Mica Units 5 and 6 and Revelstoke Units 5 and 6 than to build hydro projects on Vancouver Island. However, these Vancouver Island hydro projects would still be economical in the 1990s, after the transmission line was fully loaded up.

TABLE 6-5

VANCOUVER ISLAND LOAD RESOURCES BALANCE F

1200 MW COAL 1986-1995, NUCLEAR 1996

Year Apr-Mar	Additional Projects	Total Capacity MW	Dependable Capacity MW	Peak Load MW	Firm Energy GWh	Required Energy GWh
1982/83	Existing System	1690	1460	1450	9,520	8,610
1983/84	150 MW Gas Turbines	1840	1580	1535	9,785	9,050
1984/85	150 MW Duncan Bay	1990	1720	1625	9,970	9,520
1985/86	25 MW Ladore 3	2015	1760	1720	9,970	10,000
1986/87	150 MW Coal Thermal	2165	1850	1820	10,240	10,525
1987/88	150 MW Coal Thermal	2315	1950	1925	11,290	11,050
1988/89	150 MW Coal Thermal	2465	2055	2030	12,340	11,600
1989/90	150 MW Coal Thermal	2615	2170	2140	13,390	12,180
1990/91	160 MW Kokish Hydro	2775	2340	2260	13,620	12,790
1991/92	150 MW Coal Thermal	2925	2460	2390	14,670	13,430
1992/93	150 MW Coal Thermal	3075	2580	2520	15,720	14,100
1993/94	200 MW Pump Storage	3275	2760	2650	15,720	14,780
	Retire Georgia GT	3210	2700		15,610	
1994/95	150 MW Coal Thermal	3360	2830	2790	16,660	
1995/96	200 MW Pump Storage	3560	3020	2930	16,660	16,230
1996/97	150 MW Coal Thermal	3710	3140	3090	17,710	17,010
	Retire 138 kV Cables	3460	2890		15,830	
	630 MW Nuclear 1	4090	3100		16,880	
1997/98	New Project			3250		17,820

6.3 ALTERNATIVE GENERATION EXPANSION PLANS - (Cont'd)

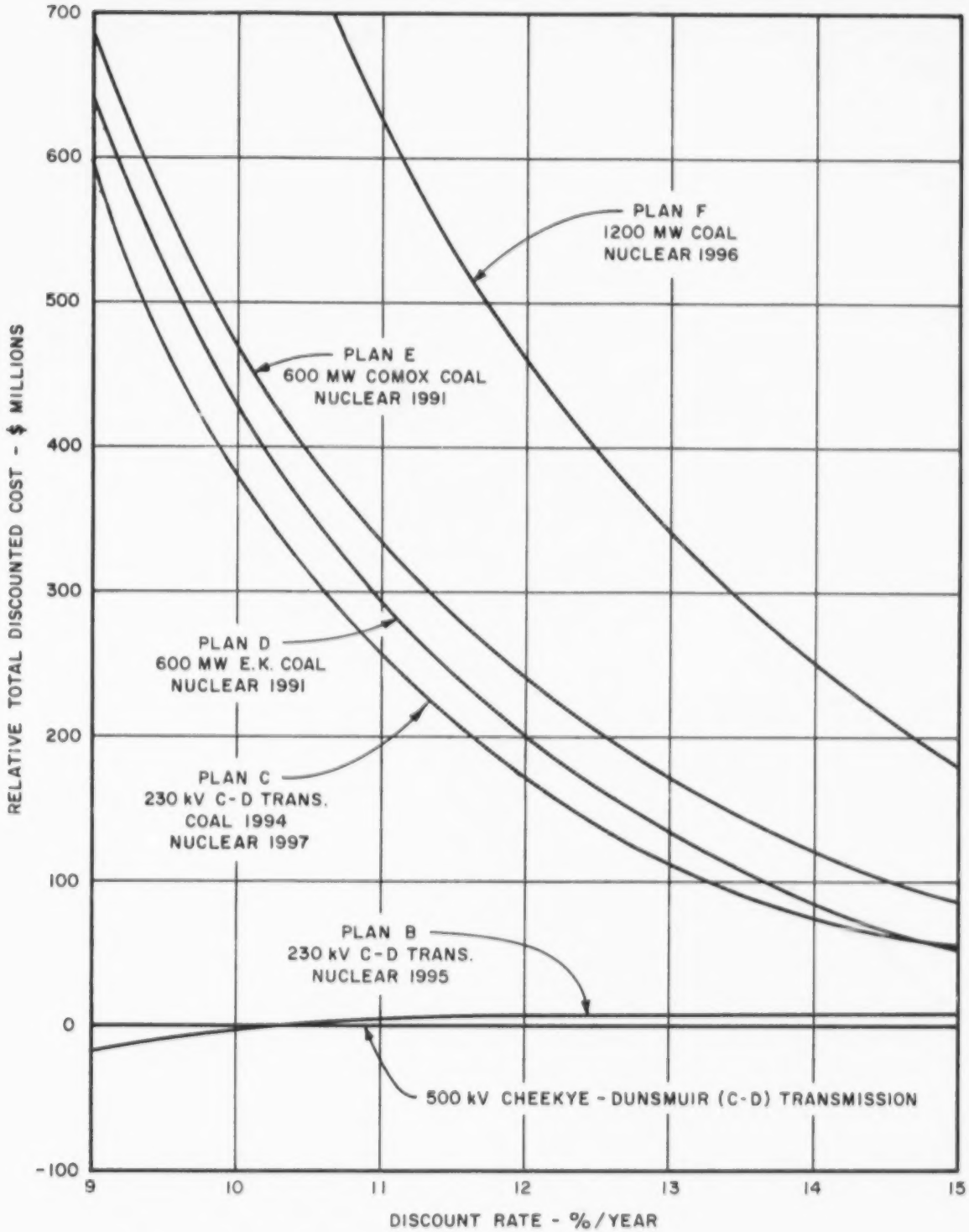
The possibility of a limited coal-fired thermal power development on Vancouver Island could also be considered. However, any limited thermal development would still require additional transmission capacity from the mainland, which could only be delayed a few years at best. The cost of such a new transmission project could not be reduced significantly even for a smaller capacity line, due to the economies of scale for such a project. Once the investment in such a transmission project has been made, it becomes more economical to build additional generation facilities on the mainland than on Vancouver Island, until the transmission is fully loaded.

6.4 RESULTS AND CONCLUSIONS

The alternative generation expansion plans summarized above were compared on the economic basis described in Section 6.1. The results of this economic comparison are shown in Exhibit 6-1. This comparison shows that the proposed 500 kV Cheekye-Dunsmuir transmission project is definitely the most economic plan for future power supply to Vancouver Island at all discount rates below 16 percent, with the possible exception of Plan B.

The 230 kV Cheekye-Dunsmuir Transmission Plan B would not differ significantly in cost from the proposed 500 kV transmission plan if a nuclear power development could be completed on Vancouver Island in 1995 (See Exhibit 6-1). However, if a nuclear development were delayed beyond this date and a higher cost 600 MW coal-fired thermal development were required instead, then this 230 kV Transmission Plan C would be $380 million more expensive at a 10 percent discount rate than the proposed 500 kV transmission plan.

COST COMPARISON OF ALTERNATIVE GENERATION EXPANSION PLANS TO SERVE VANCOUVER ISLAND



6.3 ALTERNATIVE GENERATION EXPANSION PLANS - (Cont'd)

The Vancouver Island generation alternatives are all significantly more expensive than the proposed transmission plan. With a 600 MW East Kootenay coal-fired thermal development from 1986 to 1989, and nuclear power starting in 1991, Plan D would cost $430 million more at a 10 percent discount rate than the proposed 500 kV transmission plan. If Comox coal were used instead of East Kootenay coal, the additional cost of Plan E would increase to $470 million.

If a nuclear power program is delayed in an alternative Vancouver Island generation plan, then additional coal-fired thermal power would be required after 1991, and the costs of this plan would increase still further. The costs of such a Plan F with 1200 MW of coal-fired thermal would be about $950 million higher at a 10 percent discount rate than the cost of the proposed 500 kV transmission plan.

The internal rate of return on the investment in Cheekye-Dunsmuir transmission would be over 16 percent compared to any alternative Vancouver Island generation plan. This rate of return includes annual inflation of 5.75 percent.

The higher cost of the Vancouver Island Thermal Generation Plan is due primarily to the high cost of coal as a source of thermal fuel on Vancouver Island. There would be some saving in capital costs with this plan due to elimination of the costly submarine transmission interconnection from Cheekye to Dunsmuir, but this would be outweighed in the long run by the high cost of coal for fuel. Fuel costs for a coal-fired thermal powerplant on Vancouver Island would be about 14.3 mills/kwh, compared to 6.0 mills/kwh for mainland generation at Hat Creek. (Comox fuel costs may be lower, but the additional costs of scrubbers for pollution control would more than offset this fuel cost advantage.) At an average annual capacity factor of about 60 percent, a 600 MW coal fired thermal powerplant would generate about 3100 GWh

per year. The "extra" fuel cost of this generation, at 8.3 mills/kwh for extra costs, would total about $25.7 million annually at 1977 price levels.

These costs must be compared to the alternative of investing $297 million in additional transmission facilities ($315 million for the Cheekye to Dunsmuir line, minus $18 million for the alternative Cheekye to Sechelt line), and building additional generating capacity on the mainland rather than on Vancouver Island. The levelized annual cost of these additional transmission facilities would be about $20.1 million annually at 1977 price levels, which is considerably less than the annual fuel cost penalty of coal-fired thermal generation on Vancouver Island.

These high fuel costs, combined with other changes required to make a Vancouver Island generation plan feasible, all add to the costs of such a power supply plan. The resulting total discounted cost of the alternative Vancouver Island Generation Plan D is still $430 million higher than the proposed transmission plan. The delivered total cost of East Kootenay coal would have to be reduced to about $15/ton to make this Plan D economically competitive. The cost of the Comox coal alternative Plan E is $470 million higher than the proposed transmission plan, and the delivered total cost of Comox coal would have to be reduced to $9/ton for 12,000 Btu/lb coal, or $7/ton for 9600 Btu/lb coal to make this alternative plan economically competitive. It is highly unlikely that these coal prices could be reduced to such an extent.

It can therefore be concluded that the proposed 500 kV ac Cheekye-Dunsmuir transmission interconnection to Vancouver Island will clearly be the most economic source of new power supply for Vancouver Island in 1983. The only economical variation of this plan, as shown

in Exhibit 6-1, would be a 230 kV Cheekye-Dunsmuir transmission project combined with an early nuclear power development on Vancouver Island in 1994. However, since this alternative offers no significant environmental or technical benefits, and since its total discounted cost would be the same under optimistic assumptions about nuclear availability, and would be much higher if an early nuclear development were delayed or proved unfeasible, this alternative offers no real benefits, and significant economic risks.

The Vancouver Island alternative generation plans are all much more costly. In addition, the technical feasibility and environmental acceptability of the projects included in these plans is rather uncertain. Development of the remaining hydro sites on Vancouver Island is technically feasible, but may be environmentally unacceptable. The costs of coal-fired powerplants are still uncertain, and any thermal project would involve at least a three-year delay in supplying additional base load power to the Vancouver Island power system. Nuclear power would probably be economic, but it cannot be completed soon enough, and its public acceptability remains uncertain. In short, the alternative Vancouver Island generation plans are much more costly, they would be more difficult to develop in time to meet forecast loads, and their collective environmental impact is probably much greater than that of the proposed 500 kV Cheekye-Dunsmuir transmission project and its associated mainland power.

SECTION 7.0 - LOAD REDUCTION ALTERNATIVES

Another alternative to increasing future power supply on Vancouver Island with more transmission or generation projects may be to reduce future power demands through load reduction measures. Such load reduction measures would not be able to stop future load growth completely, but they may be able to reduce it sufficiently to significantly alleviate the problems of supplying additional power to Vancouver Island, and delay the required in-service dates of future sources of power supply. The most effective and practical load reduction measures appear to be increased promotion of conservation of electricity use, promotion of industrial self-generation of electricity, and the supply of natural gas to Vancouver Island to replace electric space heating and water heating loads.

7.1 INCREASED CONSERVATION OF ELECTRICITY

(a) Energy Conservation

Energy conservation measures vary from providing educational material to physical rationing, and can be aimed at improving the efficiency of equipment and processes, or improving maintenance and operating procedures, or even radically changing lifestyles.

B.C. Hydro's current program is educational in nature, and is mainly directed at improving the efficiency with which energy is used. Better maintenance and operating procedures are also encouraged, however, through media advertising, talks to special interest groups and through the provision of technical information and general interest pamphlets. Information is provided on the financial benefits immediately available to users

through minor lifestyle changes, such as reduced temperatures for residential space heating.

The program therefore relies entirely on the voluntary participation of customers, without using coercion. It is anticipated that this program should reduce load growth by about 1 to 2 percent annually, which is small relative to total requirements, but nevertheless substantial in actual energy terms. These figures are similar to the voluntary targets set by various Canadian industrial groups as part of the Federal energy conservation program.

In the residential sector significant developments in which B.C. Hydro has and will continue to participate, are the improvement in insulation requirements, particularly the introduction of higher standards for new construction, the improvement in the efficiency of major energy using appliances such as water heaters, refrigerators, freezers and ranges, and appliance labelling to provide users with sound energy efficiency information.

Since the bulk customers use almost 50 percent of the energy on Vancouver Island it is important that these customers use their own experts effectively to ensure the efficient use of energy. To encourage this in-house approach, B.C. Hydro provides information and guidelines on how to monitor or "audit" energy use and how to establish a sound energy management program. Energy Services has conducted seminars and published specific technical information to assist industrial users. Although some success has been reported by Vancouver Island industrial bulk users, electricity represents a small part of their total energy requirements, and the most impressive savings have reduced their need for fuel oil rather than electricity.

7.1 INCREASED CONSERVATION OF ELECTRICITY - (Cont'd)

The general class accounts for about 20 percent of the energy, and although this sector is small, it has a good potential for using energy more efficiently. This is because they do not have the experts that the bulk customers do, and therefore are historically less efficient. However the diversity in energy use by hospitals, schools, offices, supermarkets, banks and service stations, for example, requires careful planning for a utility directed information program. Two particular areas have been singled out for conservation programs, namely, heating and lighting. The lighting program has been particularly successful; the first phase of a five-phase program revealed that half the users of outside lighting who were approached had already taken some action and the other half could save an average of 30 percent in lighting energy if they followed the advice provided by B.C. Hydro staff. Although the savings are impressive, it must be remembered that this represents only a small portion of the electricity used by such customers.

One anticipated effect of energy conservation is that it will not reduce the peak load as much as the average energy used. This could be particularly important if new power supply is required more for peaking capacity than for energy generation.

(b) Peak Load Management

For many years electric utilities have controlled various loads to better use their plant. In particular, night heating loads in Europe and water heaters in eastern Canada have been controlled either by time clocks or by signals sent out by the utility. Recently, advances in automatic control systems have made a number of options more attractive economically. B.C. Hydro is participating with other Canadian utilities in experiments on such devices, so that they could be quickly applied to British

Columbia if they are cost effective and are acceptable to users. It must be understood that peak load management does not reduce energy use, but simply postpones the time of use.

(c) Alternative Fuels

In encouraging the conservation of electricity it is important to also encourage the conservation of all fuels, especially non-renewable and imported fuel such as oil and propane.

Solar energy is available to users today, and B.C. Hydro can offer constructive advice to customers considering the use of solar collectors. The technology is new in British Columbia, however experience elsewhere indicates that such routine aspects as corrosion, correct installation, weathering of components, and regular maintenance must be seriously considered. To corroborate these findings, B.C. Hydro makes an effort to review and in some cases monitor local solar experiments, and is presently testing some devices on its own facilities. Sound architectural design which uses materials, layout and orientation to reduce the need for purchased energy is most important and B.C. Hydro has actively supported initiatives encouraging such "passive" solar systems.

Electricity pricing policies designed to make heavier insulation and glazing more attractive for electrically heated homes can also encourage a switch to non-renewable oil, increasing the need for imported oil, counter to stated Federal Energy Policy. This emphasizes the need for careful planning of conservation strategies.

7.1 INCREASED CONSERVATION OF ELECTRICITY - (Cont'd)

In summary, electricity conservation will play an important part in reducing customer's bills, but the effect of voluntary electricity conservation efforts, in the absence of stricter Provincial and Federal measures, is unlikely to do more than marginally delay the need for new supplies of electric power on Vancouver Island to provide reliable service.

7.2 INDUSTRIAL SELF-GENERATION

The bulk industrial loads for the forestry and mining industries on Vancouver Island constitute a large proportion of the total electric load on the Island. By 1982/83 it is forecast that the bulk peak load will be 32 percent of the total peak and the bulk energy load will be 40 percent of the total energy. It may be possible to encourage these large industrial users to generate more of their own power through self-generation or co-generation, and thereby relieve the power loads on B.C. Hydro on Vancouver Island.

There is some existing self-generation at forestry plants which use hog fuel, the wood waste by-product of the forestry industry, as a boiler fuel. The forestry industry on Vancouver Island now generates about 62 MW of power for its own use. This power is generated by co-generation, which uses a non-condensing back-pressure power turbine, and the low pressure exhaust steam from this turbine is then used as industrial process steam at the plant. The maximum co-generation attainable on Vancouver Island, based on existing process steam requirements, is estimated to be about 155 MW with 600 psig boilers, an increase of 93 MW over existing co-generation. This could be increased another 44 percent if the industry converted to 1250 psig boilers.

7.2 INDUSTRIAL SELF-GENERATION - (Cont'd)

The major constraint on increased industrial co-generation will be the availability of low cost fuel supplies. Forestry industry boilers are now fueled with both hog fuel and fuel oil. With the rapid increase of oil prices in recent years, the forestry industries are scrambling to replace oil with hog fuel as a boiler fuel to the maximum extent possible, and several hog fuel boilers have been built recently or are under construction to replace oil-fired boilers. However, surplus hog fuel supplies are limited, and after the planned boiler conversions to replace fuel oil are completed, it is expected that there will be no additional surplus hog fuel supplies available in the future on either Vancouver Island, or on the associated lower mainland coastal region.

This conclusion is also shared by the recent study on "Hog Fuel Availability in British Columbia" prepared by the British Columbia Wood Waste Energy Co-ordinating Committee, May, 1978. This study forecasts a deficit in the supply of hog fuel in the Vancouver Island and lower mainland coastal region by 1980. However, current studies are continuing in order to confirm this conclusion.

Any additional co-generation of electricity by private industry on Vancouver Island would thus require additional fuel supplies of either costly fuel oil, or possibly natural gas if it becomes available. The net thermal efficiency of industrial co-generation is about 4000 to 5000 Btu/kwh. Thus, for each kilowatt-hour of electricity generated by co-generation, an additional 4000 to 5000 Btu of fuel is required, if the energy contained in the exhaust steam is used and required in any case as industrial process steam.

If additional industrial co-generation is based on additional oil as the fuel supply, the fuel cost of this oil, at $0.50/imperial gallon for oil cost, 152,000 Btu/imperial gallon for heat content, and

7.2 INDUSTRIAL SELF-GENERATION - (Cont'd)

4000 Btu/kwh for heat rate, would be about 13.2 mills/kwh for fuel costs only. The annual capital charges for turbine-generator equipment, as well as operation and maintenance costs must be added to this to obtain total power generation costs. These costs would be too high to make oil-fired industrial co-generation economic compared to other power sources.

There may be some potential for additional economic co-generation with natural gas if it becomes available, but these costs are still rather uncertain. In any case, the total potential for additional industrial co-generation on Vancouver Island is only about 93 MW, and even if all this potential were developed, which is highly unlikely, it would be able to supply only 1 year of electric load growth on Vancouver Island.

7.3 EFFECT OF NATURAL GAS SUPPLY

The technical feasibility of constructing a natural gas pipeline from the mainland to Vancouver Island has been established, and the economic feasibility is currently being studied by B.C. Hydro. An independent study, which will also examine provincial benefits, is being conducted by the B.C. Energy Commission. Such a natural gas supply would result in a reduction of future electric load growth otherwise required to serve new space heating and water heating loads.

The earliest feasible in-service date of a natural gas supply and distribution system on Vancouver Island is estimated to be late 1982. After that date, the reduction in electric load growth that might be achieved if the projected gas load is acquired is shown in Table 7-1. In the initial period after the start of service, some existing electric loads for water heating, etc. would convert to gas, and over the long run the annual rate of electric load growth could be

reduced by about 1 percent per year. This forecast assumes that natural gas on Vancouver Island would be priced low enough to attract customers from other energy sources. This forecast does not include the recent requests for new industrial loads on Vancouver Island before 1983, which are discussed in Section 2.4.

The load forecast with gas shows that a gas supply would definitely not eliminate the need for additional power supply to Vancouver Island, and it would probably not even delay the required in-service date of the first Cheekye-Dunsmuir transmission circuit. The reductions in electric power loads due to natural gas supply are relatively insignificant conpared to total power loads in the initial years of gas availability. During this period, increases required in the load forecast due to new industrial loads are expected to be much greater than the small reductions due to gas supply. The net effect of these two adjustments is that the first Cheekye-Dunsmuir transmission circuit will be required at the earliest feasible in-service date, regardless of whether or not gas supply is available. The second Cheekye-Dunsmuir transmission circuit could possibly delayed by 1 or 2 years with a gas supply however.

The availability of a natural gas supply on Vancouver Island and its consequent reduction of the electric load forecast may also affect the relative economic ranking of the alternative plans for future power supply to Vancouver Island. This problem was studied by rescheduling each of the generation expansion sequences described in Chapter 6 for the new load forecast with gas supply. In most cases, the project in-service dates were delayed, and in some cases less desirable projects were completely eliminated, such as the 150 MW gas turbine plant and the Kokish hydro project included in the Vancouver Island generation alternatives. The resulting relative total discounted costs of the alternative plans for power supply with the reduced load forecast in Table 7-1 are shown in Exhibit 7-1.

TABLE 7-1

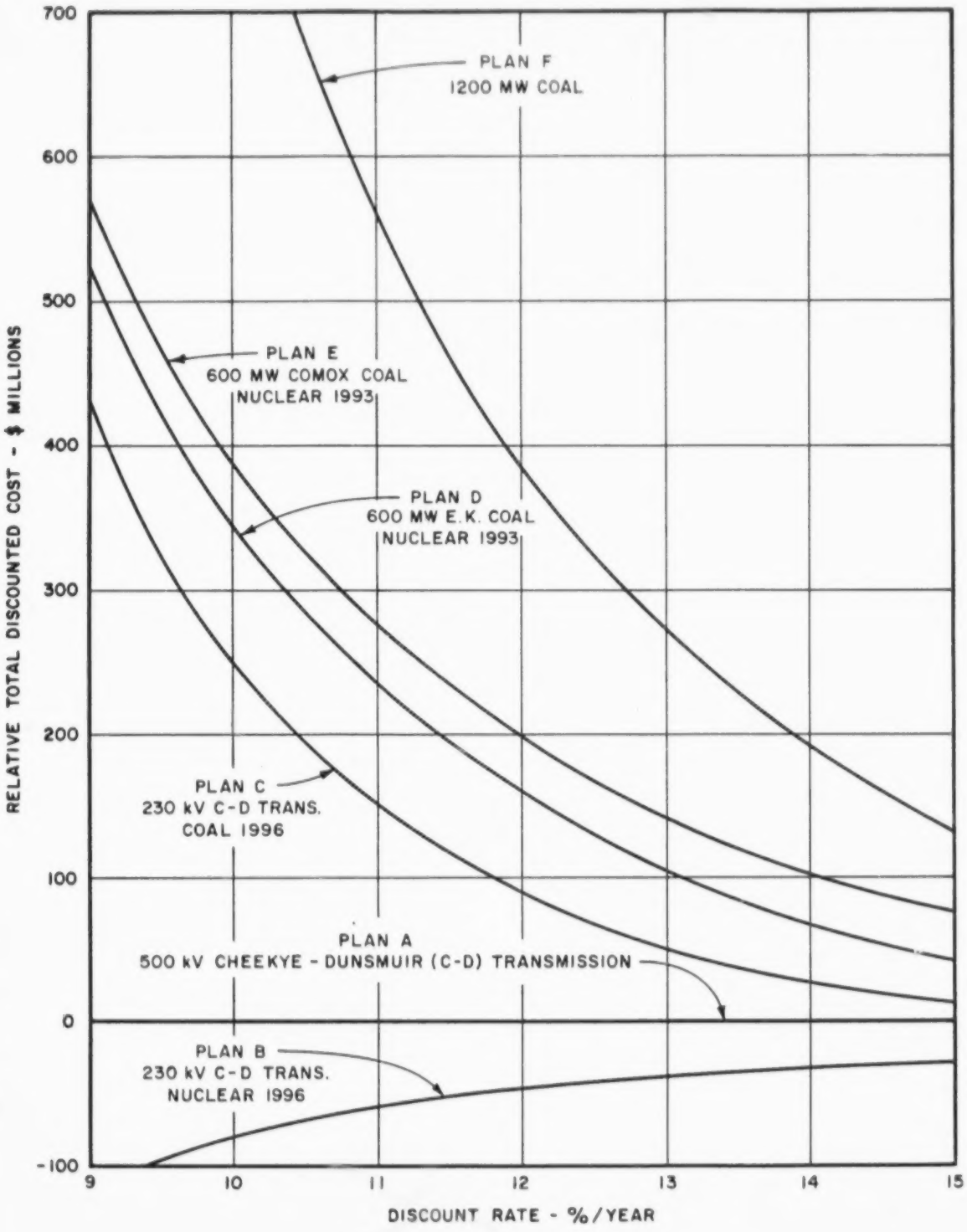
Vancouver Island Load Forecast
With and Without Natural Gas Supply

Fiscal Year (April-March)	Sept. 1977 Gross Electric Load Forecast (No Natural Gas)		Estimated Gross Electric Load Displaced by Natural Gas Starting 1982/83		Revised Gross Electric Load Forecast (Natural Gas)	
	Peak MW	Energy GwH	Peak MW	Energy GwH	Peak MW	Energy GwH
1981/82	1,365	8,120	-	-	1,365	8,120
1982/83	1,450	8,610	30	120	1,420	8,490
1983/84	1,535	9.050	60	240	1,475	8,810
1984/85	1,625	9,520	90	360	1,535	9,160
1985/86	1,720	10,000	130	490	1,590	9,510
1986/87	1,820	10,525	160	620	1,660	9,905
1987/88	1,925	11,050	200	760	1,725	10,290
1988/89	2,030	11,600	230	880	1,800	10,720
1989/90	2,140	12,180	260	1,000	1,880	11,180
1990/91	2,260	12,790	290	1,120	1,970	11,670
1991/92	2,390	13,430	320	1,240	2,070	12,190
1992/93	2,520	14,100	350	1,360	2,170	12,740
1993/94	2,650	14,780	390	1,490	2,260	13,290
1994/95	2,790	15,490	420	1,620	2,370	13,870
1995/96	2,930	16,230	450	1,750	2,480	14,480
1996/97	3,090	17,010	490	1,880	2,600	15,130
1997/98	3,250	17,820	520	2,020	2,730	15,800
1998/99	3,410	18,660	560	2,170	2,850	16,490
1999/00	3,570	19,520	600	2,330	2,970	17,190
2000/01	3,730	20,390	640	2,480	3,090	17,910
2001/02	3,900	21,290	680	2,640	3,220	18,650

Notes:

1. In-service date of gas supply is assumed to be late 1982.
2. All transmission and distribution losses are included.
3. September 1977 forecast probably underestimates total industrial load demands from 1981 to 1984, as discussed in text.

COST COMPARISON OF ALTERNATIVE GENERATION EXPANSION PLANS TO SERVE VANCOUVER ISLAND WITH GAS SUPPLY AVAILABLE



7.3 EFFECT OF NATURAL GAS SUPPLY - (Cont'd)

Exhibit 7-1 shows that, with a reduced electric load forecast resulting from a gas supply, the most economic plan for future power supply to Vancouver Island would be the 230 kV Cheekye-Dunsmuir transmission project with a nuclear power development starting in 1996.

Would this change in economic ranking affect the current planning and decision making process on the 500 kV Cheekye-Dunsmuir transmission project? Even if it were certain now that gas supply would be available and the load forecast would be reduced, it is not certain that nuclear power would be a feasible option in Plan B. If nuclear would not be available for Plan B after the 230 kV transmission became fully loaded, a coal-fired thermal development would be required instead, (Plan C in Exhibit 7-1), and the costs of the 230 kV transmission plan would increase substantially. Thus, although a 230 kV transmission alternative would offer the potential for economic savings if a gas supply were available, it would also entail an economic risk if it were developed and then nuclear power were not available. The benefits of this plan are therefore considered rather marginal and uncertain.

A final decision on the Cheekye-Dunsmuir transmission project voltage will be required before the uncertainties of the gas supply or acceptability of nuclear power can be determined. It is prudent therefore, that B.C. Hydro proceed now with the 500 kV Cheekye-Dunsmuir alternative as proposed.

SECTION 8.0 - DISCUSSION OF OTHER MULTIPLE OBJECTIVE PLANNING CRITERIA

The plans and recommendations of this study up to this stage have been based primarily on the traditional planning criterion of minimizing total discounted direct costs, subject to the constraints of technical and environmental feasibility. Often indirect benefits and costs and various degrees of environmental impact are also involved in comparing alternative plans, and these may be evaluated more appropriately from a multiple objective planning viewpoint which considers several alternative planning criteria. These other planning criteria are discussed in this chapter, which compares the merits of the proposed mainland to Vancouver Island transmission plan against an alternative Vancouver Island generation plan on several alternative accounts.

8.1 CAPITAL COST ACCOUNT

The total capital cost of the 500 kV Cheekye-Dunsmuir transmission project is about $315 million at 1977 price levels. Although it has been shown in Chapter 6 that this investment is economically justified in the long-term, it will nevertheless impose additional short-term borrowing requirements on B.C. Hydro. The feasibility of raising these additional borrowing requirements and their impact on B.C. Hydro's short-term rate structure must be considered.

Exhibit 8-1 shows the total additional capital investment requirements of the 500 kV Cheekye-Dunsmuir transmission power supply plan compared to the alternative power supply plans described in Chapter 6. The difference in accumulated total investments, at uninflated 1977 costs, is shown for each year from 1978 to 1999. There would be no significant reduction in total investment requirements from 1978 to 1985 for the Vancouver Island generation alternative Plan D, because the additional investments required for Vancouver Island power

ADDITIONAL CAPITAL INVESTMENTS REQUIRED FOR ALTERNATIVE POWER SUPPLY PLANS

(Uninflated 1977 Costs)

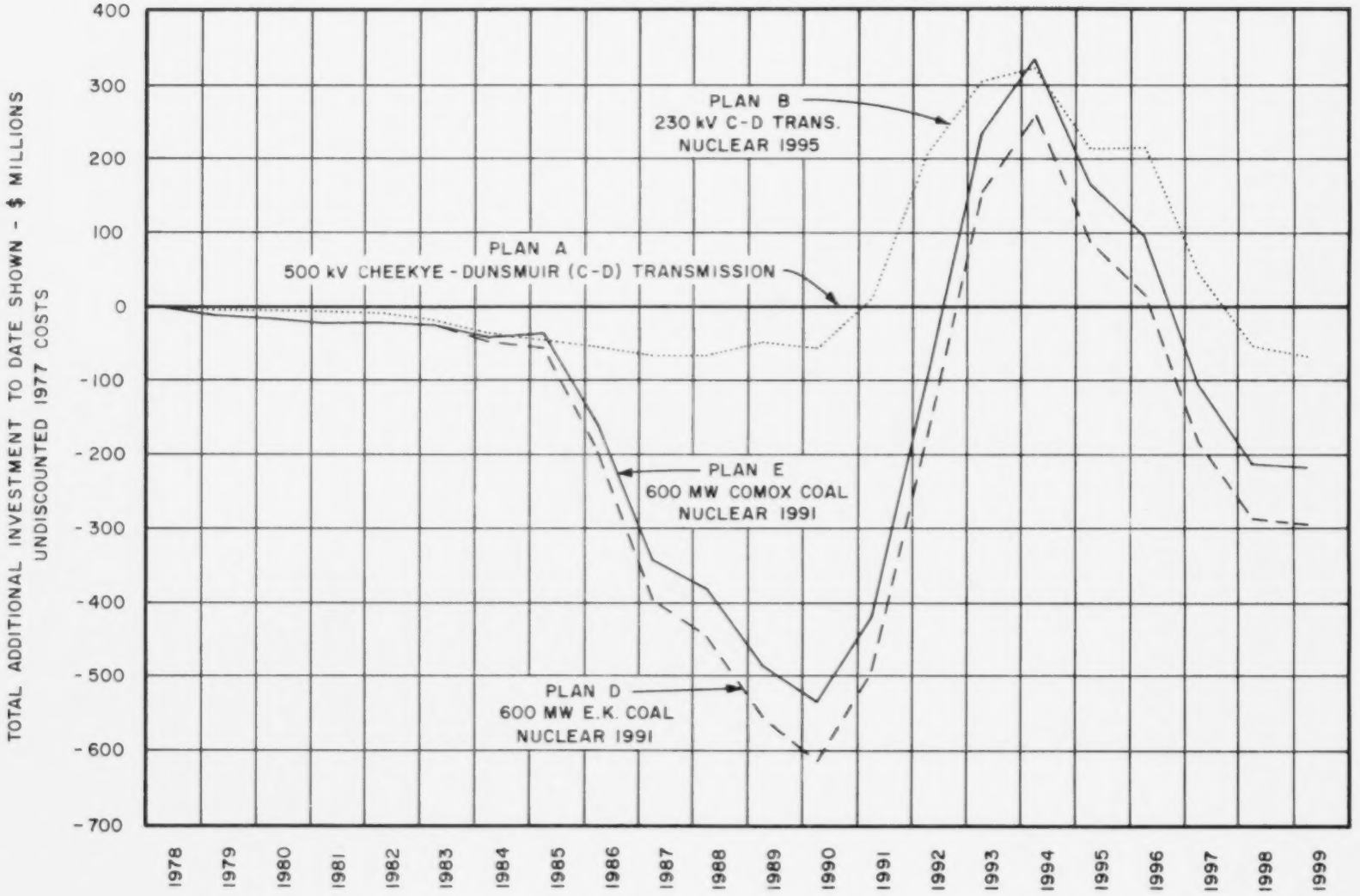


EXHIBIT 8-1

8.1 CAPITAL COST ACCOUNT - (Cont'd)

projects would almost equal the cost of the alternative 500 kV Cheekye-Dunsmuir transmission project plus additional mainland generation during this period.

From 1985 to 1991 Plan D would result in a reduction in total investment requirements as shown in Exhibit 8-1, and then from 1992 to 1996 it would result in additional investment requirements due to the simultaneous development of the capital intensive Liard hydro projects as well as nuclear power on Vancouver Island. The long-term capital investment in Plan D by 1999 would be reduced by about $300 million at 1977 price levels, approximately the cost of the 500 kV Cheekye-Dunsmuir transmission project. The long-term reduction for Plan E with a Comox powerplant would be only about $220 million.

An alternative 230 kV Cheekye-Dunsmuir transmission project with early nuclear (Plan B) would also have only a small reduction in total investment requirements for 1978 to 1990, and then a large increase in investment requirements from 1991 to 1996 due to the simultaneous development of nuclear power and the Liard hydro projects. Total long-term investment requirements for Plan B would be reduced by about $70 million at 1977 prices.

It can be concluded from these two comparisons that the 500 kV Cheekye-Dunsmuir transmission project will not result in any significant increase in B.C. Hydro's total investment requirements before 1985. After that date changes are highly variable for several years. The long-term additional investment requirement of $300 million compared to Plan D represents only about 3 to 4 percent of B.C. Hydro's total investment requirements, at 1977 costs, for major generation and transmission projects during this period.

8.2 FOREIGN EXCHANGE ACCOUNT

The foreign exchange cost of the 500 kV submarine cables required for the Cheekye-Dunsmuir transmission project is estimated to be $115 million. In view of Canada's large deficits in the current international balance of payments, would it not be advisable to save this foreign exchange expenditure by developing Vancouver Island power generation that would rely on Canada's own capital and natural resources, even if it is more expensive?

The transmission plan would rely on mainland power generation that uses low quality non-exportable coal, or renewable hydro resources. A Vancouver Island generation plan would require a minimum of 600 MW of coal-fired thermal generating capacity that would burn an average of 1.3 million tons of high quality thermal coal per year. There appear to be good prospects for export of this coal, at a current price for thermal coal at tide-water ports of about $30/ton. The annual export value of the coal required for a 600 MW power plant would thus be about $40 million per year if this coal could be exported. Over the total 35-year lifetime of this power plant, this coal consumption would be worth about 1.4 billion dollars in lost export revenues at undiscounted 1977 prices. The foreign exchange opportunity value of the coal used for an alternative thermal powerplant is thus much higher than the foreign exchange cost of the submarine cable transmission project.

8.3 REGIONAL ECONOMIC DEVELOPMENT

The government of British Columbia has stated in its recent report on Coal Policy that it wishes to encourage development of the coal industry in British Columbia. It may be inferred from this policy that the government would also like to encourage the development of the Comox coal deposits on Vancouver Island. By developing a Comox coal-fired power plant on the Island, B.C. Hydro could aid in developing

8.3 REGIONAL ECONOMIC DEVELOPMENT - (Cont'd)

this coal resource and in stimulating regional economic development on Vancouver Island.

However, Comox coal is relatively good quality thermal coal, and could be exported if it is not required for a Comox power plant. Recent discussions between B.C. Hydro and Weldwood, who own the Comox coal deposit, indicate that a viable export market exists for this coal, and that a Comox coal mine development is not in any way contingent on purchase of this coal by B.C. Hydro.

Since the development of a Comox coal mine is evidently not dependent on B.C. Hydro's plans, the only stimulus to regional development of a Vancouver Island generation plan would arise from the construction and operation of the power plants required for such a plan. If these projects were not built on the Island, they would be built on the mainland, and an equal stimulus to mainland regional development would occur. The overall benefits to the provincial economy would be roughly comparable in either case.

If a political decision were made to proceed with the Vancouver Island generation plan in spite of its higher cost for the purpose of promoting regional development, it must be recognized that this would involve imposing an indirect tax on the entire population of British Columbia, in the form of higher average rates for electric power sales, in order to subsidize an uneconomic power development and stimulate regional employment in one part of the province at the expense of the rest of the province.

8.4 ASSURANCE OF POWER SUPPLY

The design and construction of the 500 kV ac submarine cables required for the transmission plan will present several challenging technical problems. Would the alternative Vancouver Island generation plans be more reliable or easier to develop?

The problems involved in the successful development of a Vancouver Island generation plan are even more difficult and numerous. It would be difficult to meet load growth in a reliable fashion from 1983 to 1986 with such a plan, and it might be necessary to ration electric power and curtail industrial load growth until 1986, the earliest feasible date for the completion of a coal-fired powerplant. There is no assurance that water licences could be obtained for the Duncan Bay and Kokish hydro projects, both of which may have significant environmental impacts. If these projects could not be built, it would be even more difficult to meet load growth on the Island until 1986.

Additional gas turbine generating capacity could be scheduled for the interim, but the long-term availability and reliability of oil fuel supplies for gas turbine power plants will be questionable, particularly if oil shortages become more severe in the future. The alternative Vancouver Island generation plans would all burn at least 16 million gallons of fuel oil in the winter of 1985/86 and again the following winter. There is a possibility that these oil supplies may not be available for power generation if oil rationing is required in the future.

The schedule for construction of a coal-fired power plant by October 1986 will also be very tight. Coal supplies and costs for such a power plant are still speculative, and costs may well increase if the export price of coal increases in the future. The cost and reserves of Comox coal have not been proven yet, although East Kootenay coal supplies would appear to be reliable.

8.4 ASSURANCE OF POWER SUPPLY - (Cont'd)

The feasibility of nuclear power development on Vancouver Island is also uncertain at present, and will depend on finding a suitable project site, and on public acceptability of nuclear power in general.

Almost every component of the Vancouver Island alternative generation plan is subject to some uncertainty, and the feasibility of this plan has not been established to the same level of confidence as the proposed transmission plan.

8.5 ENVIRONMENTAL IMPACT

There has been widespread public concern in recent months about the environmental impact of the Cheekye-Dunsmuir transmission project along many sections of the alternative routes under study. This public opposition has been particularily strong on the Sechelt Peninsula, Nelson Island, Lasqueti Island and Qualicum Beach areas. Although no final decision has yet been made on a recommended transmission corridor, it will be impossible to avoid any environmental impact with this project, in spite of B.C. Hydro's best efforts to minimize this impact wherever possible.

The total environmental impact of an alternative Vancouver Island generation plan is expected to be significantly greater, however, than that of the proposed transmission plan. The Duncan Bay and Kokish hydro projects, if they were approved for construction, could both have an adverse environmental impact. A 600 MW coal-fired thermal plant would also have a noticeable impact from the viewpoints of coal mining or coal transport, visual aesthetics, air quality, and noise. An early nuclear development program for Vancouver Island could become a controversial public and environmental issue. If such a nuclear program were delayed or cancelled, the coal-fired thermal generating

8.5 ENVIRONMENTAL IMPACT - (Cont'd)

capacity on the Island would have to be increased, with an associate increased environmental impact and greatly increased cost for such an all-coal Vancouver Island generation plan.

An objective examination of the collective environmental impact of all the projects included in a Vancouver Island alternative generation plan would undoubtedly show that their total impact is much greater than that of the proposed Cheekye-Dunsmuir transmission project. Although this transmission project has generated some controversy recently, this is largely due to the imminence of its proposed construction. If any of the alternative hydro or thermal Vancouver Island generation projects were so far advanced in their planning and so close to the stage of actual construction, they would undoubtedly provoke an equal if not far greater public reaction to their environmental impact.

8.6 SUMMARY

In summary, the evaluation of the Cheekye-Dunsmuir transmission project from the viewpoint of several alternative planning criteria is as follows:

Discounted total Cost - Cheekye-Dunsmuir transmission project is clearly most economic.

Total Capital Cost - Cheekye-Dunsmuir project will have little effect on total borrowing before 1985. It will require a higher total investment after that date.

Foreign Exchange Account - Alternative coal-fired thermal projects would have a much higher foreign exchange opportunity cost.

8.6 SUMMARY - (Cont'd)

Regional Development - Will be similar from overall provincial viewpoint, and is not justifiable from a regional viewpoint.

Assurance of Power Supply - Cheekye-Dunsmuir project will be most reliable and easiest to develop on time.

Environmental Impact - Cheekey-Dunsmuir project will have local impacts, but these are probably less than the total impact of alternatives.

It must be concluded from the above examination of other multiple objective planning criteria that the proposed 500 kV Cheekye-Dunsmuir transmission project is still the most attractive overall plan for increasing future power supply to Vancouver Island.

APPENDIX

GLOSSARY OF TECHNICAL TERMS

ac (alternating current): current that alternates its direction of flow, usually at 60 cycles per second

base load: the minimum value of load over a given period of time

base load generating station: a generating station which is normally operated to serve the base load of a system and which, consequently, operates essentially at constant output

Btu (British thermal unit): a standard unit of heat used in measuring the available heat energy of fuels

capability: the maximum average power output of a machine, apparatus, station, or system under specified conditions for a given time interval (usually 1 hour)

capacity: the maximum output for which a machine, apparatus, station or system is rated

capacity factor: the ratio of the average load on a machine or equipment for the period of time considered, to the capacity rating of the machine or equipment

capacity reserve: the difference between the net system capability and system maximum 1-hour demand. It is the margin available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads

critical period: period of years when the limitations of hydroelectric power production due to low stream-flow conditions are most critical with respect to system load requirements

dc (direct current): current which, under normal conditions, continues to flow in one direction only

demand: the rate at which electric energy is delivered to the system or to customers averaged over a specified interval of time

drawdown: the distance that the water surface of a reservoir is lowered as the result of the withdrawal of water

ehv (extra high voltage): term usually associated with voltages in the range of 345 kV to 765 kV

electric system: all physically connected electric facilities operated under one control

energy: the doing of work; electric energy is usually measured in kilowatt-hours

energy capability: the average energy output of a machine, apparatus, station or system over a specified time interval (usually 1 year)

firm energy: a supply of electric energy that is available on an assured basis

fiscal year: the financial year, for B.C. Hydro April 1st to March 31st

fixed operating costs: costs of operating a plant which do not vary or fluctuate with changes in operation or utilization of plant

forced outage: the breakdown or loss of a major system component due to some cause which requires the electrical isolation of the component from the remainder of the power system

fossil fuels: coal, oil, or gas used to heat a thermal powerplant

generating station: a station containing apparatus for producing electric energy

heat rate: a measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is defined as the total Btu content of fuel burned for electric generation divided by the net kilowatt-hour generation output of the station

HVdc (high voltage direct current): term usually associated with the use of direct current at transmission voltage, generally above 50 kV

installed capacity: the total of the capacities of the generating units in a station or system

integrated system: that portion of the B.C. Hydro electric system capable of being operated on a coordinated basis

interconnection: a transmission tie permitting a flow of power and energy between the facilities of two electric systems in either direction

kV (kilovolts): an abbreviation for 1000 V, a unit of electrical potential difference

kW (kilowatts): an abbreviation for 1000 W, a unit of power

kWh (kilowatt-hour): an abbreviation for 1000 Wh, a unit of energy

load: the amount of electrical energy delivered or required

load center: the location at which the load of a given area is assumed to be concentrated

load factor: the ratio of the average demand in kilowatts supplied during a designated period to the maximum demand occurring in that period

megawatt (MW): a thousand kilowatts

operating reserve: the unloaded generating capacity of the system's firm resources ready to take load upon demand

peaking capacity: generating capacity available to assist in meeting that portion of peak load which is above base load

peak load: the maximum load demand in a stated period of time (usually 1 hour)

plant capacity factor: the ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant

power: the time rate of generating, transferring or using electric energy, usually expressed in kilowatts

secondary energy: electric energy that does not have assured availability

stability: a property of the power system which indicates that all generating sources on it are successfully operating in parallel

system reserve: the generating capacity available to the system in excess of that required to carry the maximum 1-hour demand

thermal plant: a thermal powerplant; may be either fossil fuel or nuclear, but when undesignated it usually refers to fossil fuel powerplants

transmission line: a circuit in a transmission system

transmission system: an interconnected group of transmission lines and associated equipment for the transporting or conveying of electric energy in bulk to convenient points at which it is subdivided for delivery to customers via a distribution network